STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 24-E-0461 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service.

CASE 24-G-0462 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.

ORDER ADOPTING TERMS OF A JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLANS

Issued and Effective: August 14, 2025

TABLE OF CONTENTS

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At a session of the Public Service Commission held in the City of Albany on August 14, 2025

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
James S. Alesi
David J. Valesky
John B. Maggiore
Uchenna S. Bright
Denise M. Sheehan
Radina R. Valova

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ORDER ADOPTING TERMS OF A JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLANS

(Issued and Effective August 14, 2025)

BY THE COMMISSION:

INTRODUCTION

In this Order, the Commission approves the terms of the attached Joint Proposal, filed on May 13, 2025, establishing three-year rate plans for electric and gas delivery service provided by Central Hudson Gas & Electric Corporation (Company) for the period encompassing July 1, 2025, to June 30, 2028.

The Company, trial staff of the Department of Public Service (Staff), Multiple Intervenors (MI), and Walmart, Inc.

signed the Joint Proposal (collectively the Signatory Parties). The Public Utility Law Project of New York, Inc. (PULP), the Utility Intervention Unit of the New York State Department of State, Division of Consumer Protection (UIU), Dutchess County, and the Town of Olive Conservation Advisory Council have stated that they do not oppose the Joint Proposal. Communities for Local Power (CLP) opposes the Joint Proposal, as do New York State Assemblymember Sarahana Shrestha and United States Congressperson Josh Riley, who joined these proceedings in their individual capacities.[1]

For the reasons stated below, we approve and adopt the terms of the Joint Proposal and supporting schedules as they are in the public interest. Contrary to the arguments of the opposing parties, we find that the terms of the Joint Proposal ensure the Company's continued provision of safe and reliable service at just and reasonable rates; fall within the range of potential litigated outcomes or otherwise provide benefits to ratepayers that would not have been achieved in fully litigated proceedings, such as multi-year rate certainty; and are consistent with the environmental, social, and economic policies of the Commission and the State, including New York's Climate Leadership and Community Protection Act (CLCPA). In addition, the Joint Proposal includes an earnings sharing mechanism, and provides a multitude of benefits for low-income customers, including the continuation of monthly bill discounts for those customers and voluntary extreme weather protections, enhanced efforts to enroll additional low-income households into the Company's Energy Affordability Program (EAP), new incentives to boost participation in the EAP, and the requirement that the

[1] For the Many, Key Capture Energy and the New York Power Authority do not take any position on the Joint Proposal.

Company waive finance charges for customers with short-term payment agreements beginning in Rate Year (RY) 2.[2]

BACKGROUND

The Company currently operates under a Commission Order establishing electric and gas rates "for the period starting July 1, 2024, and ending June 30, 2025, and that will continue until changed by the Commission."[3] Pursuant to Public Service Law (PSL) §66(12), the Company filed amendments to its electric and gas tariff schedules on August 1, 2024, proposing to increase its annual electric and gas delivery revenues. More specifically, the Company sought to increase its electric delivery revenues by approximately $69.4 million and its gas delivery revenues by approximately $27.0 million. In its rebuttal filing submitted on December 18, 2024, the Company updated its requested base delivery revenue increases, before moderation, to $79.6 million for electric and $27.9 million for gas. The Company proposed applying the entire amount of its existing net regulatory liability balances of $22.2 million for electric and $15.3 million for gas to mitigate those increases, which would have resulted in reduced increases in RY1 but higher increases in future years after those credits were exhausted.[4] The requested revenue requirements reflect a common equity ratio of 48.0% for the Company and a return on equity (ROE) of 10.0%. In its filing, the Company stated that drivers for the revenue increases include the need to replace aging or obsolete

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[2] Joint Proposal, pp. 31-34, 52-53. RY1, RY2, and RY3 consist of the 12 months ending June 30, 2026, June 30, 2027, and June 30, 2028, respectively.

[3] Cases 23-E-0418 et al., Central Hudson – Rates, Order Establishing Rates for Electric and Gas Service (issued July 18, 2024) (2024 Rate Order), p. 1.

[4] Hearing Exhibit 394 (Staff Policy Panel Testimony), p. 7.

infrastructure; labor costs, including the need to hire staff to focus on protecting its critical infrastructure systems from cybersecurity threats; and increases in uncollectable expenses related to the growth in customer arrears.

By Secretary Notice the Commission suspended the effective date of the Company's rate filings and initiated these proceedings to examine the Company's proposals.[5] The assigned Administrative Law Judges (Judges) conducted a procedural and technical conference and issued a ruling establishing a litigation schedule, including dates for the filing of testimony and commencement of an evidentiary hearing.[6] The parties filed responsive testimony in November 2024 and rebuttal testimony in December 2024.

Pursuant to the Commission's Settlement Rules and Guidelines, the Company filed a Notice of Impending Settlement Negotiations on December 10, 2024, and, relatedly, requested postponement of the evidentiary hearing and consented to an extension of the suspension period, subject to a "make-whole" provision. The Company subsequently agreed to similar extensions of the suspension period, again subject to a "make-whole" provision. The Commission issued an Order on June 13, 2025, extending the maximum suspension period of the effective date of the filed tariff leaves through October 31, 2025. During the period of settlement negotiations, a Settlement Judge was appointed to ensure the expedient, efficient, and fair scheduling and conduct of the ongoing settlement discussions.

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[5] Notice of Suspension of the Effective Date of Major Rate Changes and Initiation of Proceedings (issued August 19, 2024). On December 11, 2024, pursuant to PSL §66(12)(f), the Secretary issued a Notice of Further Suspension of the Effective Date of Major Rate Changes, extending the effective suspension period through June 30, 2025.

[6] Ruling on Schedule (issued September 5, 2024).

Settlement negotiations ultimately resulted in the filing of the Joint Proposal on May 13, 2025. After moderation to reduce rate impacts on customers in RY1, the Joint Proposal would result in revenue requirement increases for electric delivery service of $29.7 million (5.5% delivery and 2.9% total revenue) in RY1, $31.6 million (5.3% delivery and 2.9% total revenue) in RY2, and $34.5 million (5.3% delivery and 3.0% total revenue) in RY3. The Joint Proposal would result in moderated gas delivery revenue requirement increases of $14.5 million (8.8% delivery and 5.4% total revenue) in RY1, $15.9 million (8.7% delivery and 5.6% total revenue) in RY2, and $17.5 million (9.0% delivery and 5.8% total revenue) in RY3. The proposed revenue requirements continue the common equity ratio of 48% for the Company and the ROE of 9.5% that was authorized under the 2024 Rate Order.[7]

Although the actual bill impacts of the proposed changes would vary based on revenue allocation and rate design, the Joint Proposal states that average total monthly electric bill increase for residential customers would be $5.43 (3.12%) in RY1, $6.25 (3.48%) in RY2, and $6.62 (3.57%) in RY3,[8] and the total monthly gas bill impact for residential customers would be $7.73 (5.19%) in RY1, $11.27 (7.2%) in RY2, and $12.37 (7.37%) in RY3.[9] The Joint Proposal further provides that low-income customers will see a reduction in their total monthly electric

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[7] 2024 Rate Order, p. 71.

[8] Joint Proposal, Appendix Q, pp. 1-6.

[9] Joint Proposal, Appendix Q, pp. 15, 18, 21. The total annual gas bill impacts in dollars shown in Appendix Q are divided by 12 to arrive at an average total monthly bill impact in each rate year.

bill of $3.85 (-4.2%) per month and an increase in their monthly gas bill of $1.26 (1.08%) in RY1.[10]

Statements in Support of the Joint Proposal were filed by the Company, Staff, MI, and Walmart, and Statements in Opposition were filed by CLP and Shrestha. An evidentiary hearing on the Joint Proposal was conducted by the Judges on June 16, 2025, to admit exhibits into evidence and to allow Riley to cross-examine a joint panel consisting of witnesses from Staff and the Company. Post-Hearing briefs and post-Hearing reply briefs were filed by the Company, Staff, and Riley.

NOTICE OF PROPOSED RULE MAKING AND PUBLIC COMMENTS

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking was published in the State Register on October 16, 2024, for both the electric and gas rate filings (SAPA Nos. 24-E-0461SP1 and 24-G-0462SP1, respectively). Moreover, in a Notice Soliciting Comments and Announcing In-Person Public Statement Hearings, comments were solicited, due July 31, 2025. The Judges presided over three in-person public statement hearings held within the Company's service territory.

At the public statement hearings, 56 people provided spoken comments. Speakers commented primarily on affordability concerns, dissatisfaction with the quality of the Company's customer service, ongoing billing disputes, and concerns regarding profits earned by the Company's parent company, Fortis, Inc. Many speakers also supported local efforts to

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[10] Joint Proposal, Appendix Q, pp. 1, 15. Estimated electric bill impacts for low-income customers for RY2 and RY3 are found in the Joint Proposal, Appendix Q, pp. 3, 5. Estimated gas bill impacts for low-income customers for RY2 and RY3 are found in the Joint Proposal, Appendix Q, pp. 18, 21.

municipalize the Company, expressing the belief that doing so would lower their energy costs. Speakers also suggested reducing executive salaries and bonuses to decrease the burden on ratepayers.

In addition, the Commission's website contains approximately 200 comments filed in the electric and gas proceedings.[11] Similar to those provided at the public statement hearings, comments were overwhelmingly opposed to the requested rate increases, mainly citing the current high level of unaffordability, the Company's ongoing billing problems, and dissatisfaction with the level of customer service provided. Other topics mentioned included the amount or percentage of the delivery charges on customer bills relative to the energy commodity component, alleged mismanagement of the Company, deficiencies in the Company's infrastructure, and complaints about the level of profit the Company, as a regulated monopoly, is allowed to attain for its corporate parents.

STATUTORY AND REGULATORY FRAMEWORK

Pursuant to PSL §65(1), in establishing electric and gas rate plans, the Commission must find that the proposed rates assure the continuation of safe and adequate service at just and reasonable rates and produce a result that is in the public interest. In evaluating what constitutes a reasonable rate, the Supreme Court of the United States has cautioned that, in order to avoid an unconstitutional taking of property dedicated to public service, utility rates must be set at a level that allows the utility an opportunity to earn a return on the value of its property that is comparable to the return available to other

[11] An overwhelming majority of the comments were submitted prior to the filing of the Joint Proposal.

companies with a similar risk profile.[12] Thus, while the Commission is empowered to consider any factor it deems relevant in setting utility rates, it must in all cases give "due regard ... to a reasonable average return upon capital actually expended."[13] As the Supreme Court explained, "[t]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."[14]

As we evaluate the proposed rate plan in light of the requirements of the applicable statutes, we are mindful that courts in New York will not disturb a rate set by the Commission unless the rate lacks a rational basis or reasonable support in the record.[15] In addition, in considering arguments calling for a departure from prior decisions, we are cognizant that "[a] decision of an administrative agency which neither adheres to its own prior precedent nor indicates its reason for reaching a different result on essentially the same facts is arbitrary and capricious."[16]

The Commission will adopt the terms of a negotiated Joint Proposal only upon a finding that the terms, considered as a whole, meet the public interest standard in PSL §65(1).

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[12] Bluefield Waterworks & Improvement Co. v. Public Serv. Commn. of West Va., 262 U.S. 679, 692-693 (1923).

[13] Matter of Abrams v. Public Serv. Commn. of State of N.Y., 67 N.Y.2d 205, 212 (1986).

[14] Bluefield Waterworks, supra, at 693.

[15] See Matter of New York Tel. Co. v. Public Serv. Commn. of State of N.Y., 95 N.Y.2d 40, 48 (2000); Matter of Abrams, supra, at 212.

[16] Matter of Charles A. Field Delivery Serv. v. Roberts, 66 N.Y.2d 516, 516-517 (1985).

Factors to consider in evaluating a Joint Proposal include whether the Joint Proposal is consistent with the environmental, social, and economic policies of the Commission and the State; whether it falls within the range of reasonable outcomes that likely would have resulted in a fully litigated proceeding; and whether the record provides a rational basis for the Commission's adoption of it.[17] The Commission also must consider whether the Joint Proposal balances the protection of consumers with fairness to investors and the long-term viability of the utility. The individual, interrelated compromises negotiated by the parties will not be disturbed absent a demonstration that a challenged provision of the agreement is inconsistent with sound policy, outside the range of likely litigated outcomes, or contrary to the protection of ratepayers, fairness to investors and the long-term viability of the Company.[18] In addition, upon an application for a major change in rates, PSL §66(19)(c) requires the Commission to review the electric and gas corporation's "compliance with the directions and recommendations made previously by the Commission, as a result of the most recently completed management and operations audit."

Finally, CLCPA §7(2) requires State agencies to "consider whether their [administrative] ... decisions are inconsistent with or will interfere with the attainment of the established statewide greenhouse gas [GHG] emission limits established in" Environmental Conservation Law (ECL) Article 75. In addition, CLCPA §7(3) prohibits State agencies from issuing decisions that "disproportionately burden disadvantaged

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[17] Cases 90-M-0255 and 92-M-0138, Proceeding on Motion of the Commission Concerning its Procedures for Settlements and Stipulation Agreements, Opinion 92-2, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines (issued March 24, 1992) (Settlement Guidelines).

[18] Id.

communities as identified pursuant to [ECL §75-0101(5)]" and requires prioritizing reductions of GHG emissions and co-pollutants in such disadvantaged communities. As the Commission has previously explained, however, the requirements of the CLCPA do not exist in a vacuum and must be balanced against the Commission's core mandate as defined by the Public Service Law, which is to act on behalf of the public in ensuring safe and adequate service at just and reasonable rates.[19]

THE JOINT PROPOSAL

Term

The Joint Proposal establishes a three-year rate plan consisting of three successive individual rate years beginning July 1, 2025, and ending June 30, 2028. The Joint Proposal contains a provision pursuant to which the Company agrees to not file a new electric or gas rate case for rates to become effective prior to July 1, 2028.

As observed by one of the Signatory Parties, the three-year term of the proposed rate plan is not atypical for rate cases resolved through settlement and its length provides advantages for ratepayers that cannot be achieved through a fully litigated case, such as "moderation" of rate increases over multiple years.[20] A fully litigated rate plan, as was adopted by the Commission to establish the rates being superseded by this order, does not allow for such moderation of rate increases over time; rather, it generally allows the Company to file at any time after the litigated rate order is issued. In contrast, a defined multi-year rate plan prevents the filing of immediate successive rate cases with the

[19] Cases 22-E-0317 et al., NYSEG and RG&E – Rates, Order Adopting Joint Proposal (issued October 12, 2023), p. 55.

[20] See MI Statement in Support, pp. 6-7.

Commission, such as occurred here, which allows the parties and the Commission to adjust the timing of successive rate increases to minimize rate impacts.

Revenue Requirements

As explained above, the Company proposed unmoderated one-year revenue requirement increases of approximately $79.6 million for electric and $27.9 million for gas.[21] The Joint Proposal provides that the Company's unmoderated electric revenue requirements will increase by approximately $46.4 million in RY1, $30.7 million in RY2, and $21.7 million in RY3; unmoderated gas revenue requirements will increase by approximately $19.0 million in RY1, $13.9 million in RY2 and $16.9 million in RY3.[22] Thus, for RY1, the Joint Proposal reduced the requested one-year increases by approximately 42.0% for electric and 32.0% for gas.

The Joint Proposal further provides for the use of electric and gas bill credits to levelize and moderate the impact of the revenue increases.[23] The bill credits are derived from projected electric and gas regulatory credits owed to customers, as well as the partial use of an electric rate base credit that originated from the sale of the Company's electric

[21] Hearing Exhibit 150 (Company Revenue Requirement Panel Exhibit RRP-1); Hearing Exhibit 288 (Company Revenue Requirements Panel Rebuttal Exhibit RRP-1R), Schedule A, p. 2; Hearing Exhibit 289 (Company Revenue Requirements Panel Rebuttal Exhibit RRP-2R), Schedule A, p. 2.

[22] Joint Proposal, p. 7.

[23] Id., pp. 7-8; Hearing Exhibit 513 (Response to IR ALJ-9).

generation assets.[24] The moderated rates and charges in the Joint Proposal are designed to produce additional electric delivery revenue and typical residential monthly electric bill impacts[25] as follows:

	RY 1	**RY 2**	**RY 3**
Revenue Requirement Increase	$29.7 million	$31.6 million	$34.5 million
Delivery Revenue Percent Increase	5.5%	5.3%	5.3%
Average Monthly Bill Impact	$5.43	$6.25	$6.62
Average Percentage Monthly Bill Increase	3.1%	3.5%	3.6%

For gas, the additional delivery revenue and approximate total monthly bill dollar and corresponding percentage increases under the terms of the Joint Proposal[26] are:

[24] Company Statement in Support, pp. 10-11; Staff Statement in Support, p. 7. These regulatory liabilities are identified in more detail in Appendix I to the Joint Proposal. For the most part, the electric and gas bill credits will be allocated to each service class in proportion to class responsibility for the delivery increase and will be refunded on a kilowatt-hour or kilowatt basis for electric or on a Ccf basis for gas through the existing Electric Bill Credit Mechanism and Gas Bill Credit Mechanisms (Joint Proposal, p. 7).

[25] Joint Proposal, p. 8 and Appendix Q, pp. 1-6.

[26] Joint Proposal, p. 8 and Appendix Q, pp. 15, 18, 21.

	RY 1	RY 2	RY 3
Revenue Requirement Increase	$14.5 million	$15.9 million	$17.5 million
Delivery Revenue Percent Increase	8.8%	8.7%	9.0%
Average Monthly Bill Impact	$7.73	$11.27	$12.37
Average Percentage Monthly Bill Increase	5.2%	7.2%	7.4%

The monthly bill increases do not account for upward adjustments resulting from the make-whole provision in the Joint Proposal. For illustrative purposes, the estimated RY1 average percentage monthly bill increases assuming a two-month make whole (i.e., July and August 2025) are 3.4% for electric and 5.3% for gas, rather than 3.1% and 5.2%, respectively.[27]

1. Sales Forecast

The Joint Proposal forecasts electric sales volume and customers for each Rate Year as follows: electric delivery volumes of 5,186,322 megawatt-hours (MWh) and 323,474 customers in RY1; 5,274,214 MWh and 323,569 customers in RY2; and 5,391,642 MWh and 323,679 customers in RY3.[28] For gas, the Joint Proposal forecasts gas delivery volumes to be 19,799,748 Mcf and 89,194 customers in RY1; 19,691,862 Mcf and 89,319 customers in RY2; and 19,602,781 Mcf and 89,441 customers in RY3.[29] In light

[27] Hearing Exhibit 512 (Response to IR ALJ-8). The monthly bill impacts in RY1 from the Company's initial filing would have been 5.3% for electric and 5.9% for gas, respectively. (Id.).

[28] Joint Proposal, Appendix N, pp. 1, 3.

[29] Id., p. 17.

of its concerns with the Company's use of composite statistically adjusted end-use variables, which Staff alleged made the Company's models non-transparent and prevented the evaluation of the impact of individual underlying variables, Staff developed its own econometric models to forecast the Company's customers and sales, using data updated through August 2024.[30] The forecasts contained in the Joint Proposal are based on Staff's modeling and the Company's post-model adjustments for the incremental impacts of electric vehicles (EVs), solar photovoltaics (PVs) and heat pump usage.[31] As the Company notes, its agreement to use Staff's forecasts for sales and volumes represents a concession on the part of the Company.[32] Inasmuch as the forecasts reflect Staff's modeling improvements and account for the changes in usage patterns due to EVs, solar PV and heat pumps, we find that these consensus forecasts are reasonable.

As in the Company's past two rate plans, the revenue requirements include an imputation of forecasted revenues from Danskammer, a gas-powered generating station.[33] The Joint Proposal provides that Danskammer Service Class (SC) 11 gas delivery revenue be excluded from the forecast, that the imputation of $1.0 million be allocated to each class in proportion to such class's responsibility for overall delivery

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30 Hearing Exhibit 411 (Staff Sales Forecasting Panel Testimony), pp. 21-23, 34-35, 39, 41, 44.

31 Id., pp. 14-15; Staff Statement in Support, pp. 56-57.

32 Company Statement in Support, p. 22.

33 Cases 23-E-0418 et al., supra, Recommended Decision (issued May 1, 2024), pp. 527-529; Cases 20-E-0428 et al., Central Hudson Gas & Electric Corporation – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued November 18, 2021) (2021 Rate Order), attached Joint Proposal, pp. 34-35.

rate increases, and that the Company will defer for future pass back/collection from customers the amount of actual revenues above or below this revenue imputed into base delivery rates.[34] In light of past practice and given the uncertainty surrounding Danskammer's repowering plans, the imputation of $1.0 million related to Danskammer revenues and continuation of the existing deferral mechanism is reasonable and in the public interest.

2. Discussion of the Opposition

Various parties either oppose or decline to support the Joint Proposal on the grounds that the rate impacts resulting from the allowed revenue requirement increases are too high. Although PULP acknowledges that enhancements to the Company's EAP will positively impact the service territory's most vulnerable population, it nevertheless declined to support the Joint Proposal due to its concern that the proposed bill impacts would exacerbate the issue of affordability for the approximately 95% of the Company's customers who are not enrolled in the EAP.[35] CLP also applauds the Company's commitment to outreach actions aimed at increasing enrollment in the EAP. However, CLP opposes the revenue requirements set forth in the Joint Proposal because it believes that the resultant rate increases will cause many customers to be unable to pay their utility bills. CLP argues that the proposed rate increases will put customers' safety at risk by impeding their access to gas and electricity for heating and cooling.[36]

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[34] Joint Proposal, p. 28.

[35] PULP Statement in Neutrality, pp. 1, 6. The overall service area rate of participation for residential customers in the Company's EAP is 4.6% (Company Statement in Support, p. 28).

[36] CLP Statement in Opposition, pp. 3-6.

Shrestha states that the bill impacts projected by the Joint Proposal are unaffordable and counter to the public interest.[37]

MI indicates that it remains troubled by the projected rate impacts and, therefore, supports the Joint Proposal only reluctantly and in the context of previously decided matters with which it disagrees. MI acknowledges that it would not be appropriate to challenge those collateral matters in a rate case but nevertheless urges the Commission to reevaluate its policies, which MI claims would limit the pace and magnitude of delivery rate increases.[38] MI strongly supports the use of net regulatory liabilities to moderate what would otherwise be considerably higher delivery rate impacts,[39] but emphasizes that it remains "very concerned that rising electric and gas delivery rates, driven in part by system expansion and reinforcement investments necessitated by State policy initiatives, are increasing at a rate that is unsustainable and may require greater moderation in the Company's next rate filing to avoid unacceptable customer rate impacts."[40] However, despite its concerns about the impact of the rate increases on customers, MI maintains the Joint Proposal represents a better outcome than that likely to have resulted if these cases were litigated, noting that the Joint Proposal provides some degree of rate

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[37] Shrestha Statement in Opposition, p. 1.

[38] MI Statement in Support, pp. 8-12.

[39] Id., pp. 12-13.

[40] Id., p. 11. MI cites to eight provisions of the Joint Proposal that it identifies as encompassing millions of dollars in spending responsive to State social and environmental policies, including electric and gas capital investments, non-wires alternatives, leak-prone pipe removal, leak management, increased spending and outreach for the Company's EAP, extreme weather protections, energy efficiency program costs, and promotion of NPAs (Id., p. 22).

certainty, provides for the beneficial deployment of customer credits, and contains earnings sharing mechanisms.[41]

Riley claims that the Company has failed to adequately demonstrate a need to raise rates at all, noting that two months after it filed this rate case the Company represented to investors, in a 2024 Q3 Quarterly Report for the period ended September 30, 2024, that it had sufficient funding "for the foreseeable future."[42] According to Riley, it was disingenuous and contradictory for the Company to file for an increase in rates while at the same time informing investors that the Company was financially sound. Riley argues that, because the Company has not sufficiently demonstrated its need for the proposed rate increases or adequately explained how its statements regarding its finances can be reconciled, the Joint Proposal cannot be found to be in the public interest.[43]

The Company counters that the Joint Proposal reflects significant compromises as compared to the Company's initial filings and will result in rates that are just, reasonable, and consistent with both the public interest and the outcomes that

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[41] Id., pp. 11-12, 22.

[42] Riley Post-Hearing Brief, p. 2, citing the CH Energy Group, Inc. & Central Hudson Gas & Electric Corp. Quarterly Financial Report for the Period ended Sept. 30, 2024, p. 51 (available at: https://www.chenergygroup.com/financial%20information/CHEnergyGroup_2024_Q3.pdf (accessed July 15, 2025) (Q3 Quarterly Financial Report). In his Post-Hearing Reply Brief at p. 5, Riley cites similar language in the Company's latest Quarterly Financial Report for the Quarter ending March 31, 2025, at p. 25 (available at: https://www.chenergygroup.com/financial%20information/CHEnergyGroup_2025_Q1.pdf (accessed July 15, 2025)).

[43] Riley Post-Hearing Brief, pp. 1-4; Riley Post-Hearing Reply Brief, pp. 2-5. Riley's further challenges to the ROE contained in the Joint Proposal are addressed in the ROE section of this Order.

likely would have resulted from litigation.[44] The Company points to the consumer protection and EAP provisions of the Joint Proposal – discussed in the Customer Service and Low-Income Programs sections of this Order – as well as the use of regulatory liabilities to mitigate rates over the three-year term of the proposed rate plans, which help smooth customer bill impacts and provide rate stability, benefits that would not have been achievable in a litigated case.[45] Further, the Company asserts, the proposed rate increases are necessary for the Company to provide all customers safe, reliable and adequate service.[46] As for Riley's arguments regarding the allegedly inconsistent statements the Company made about the stability of its finances, the Company explained that the statements made in its rate filings and to its investors are not "mutually exclusive," as claimed by Riley. Rather, the Company contends, the flaw in Riley's argument is that he overlooks the forward-looking nature of ratemaking.[47] The Company explains that the rates approved in the 2024 Rate Order were sufficient to fund the Company's operations through June 30, 2025. Thus, when it reported to its investors in September 2024 that its rates, together with equity infusions and financing, were sufficient "for the foreseeable future," the Company was, in effect, representing that it was financially secure until June 30, 2025. However, the Company further asserts, and Staff agrees, that the rates set in the 2024 Rate Order were not necessarily sufficient to sustain its financial integrity beyond June 30, 2025, which

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44 Company's Reply Statement in Support, pp. 1-2.

45 Id., p. 4.

46 Id., pp. 5-6.

47 Company Post-Hearing Brief, pp. 7-8; Staff Post-Hearing Reply Brief, p. 3.

is why it was necessary for the Company to file in August 2024 for new rates that would be effective on July 1, 2025.[48]

Staff states that it is sensitive to the concerns raised by parties about the rate increases, but maintains that the proposed increased revenue requirement appropriately balance the need for additional revenue to ensure that the Company can continue to provide safe, adequate, and reliable service while providing no more revenue than necessary and limiting the impact of those increases on customers.[49] Echoing MI, Staff also asserts that the delivery rate increases reflect the recovery of costs necessary to remain in compliance with regulatory requirements, as well as costs of property taxes and income taxes, all of which are outside the Company's control.[50] Moreover, Staff notes that CLP presents no evidence to support its claim that the Joint Proposal will result in a reduced commitment by the Company to ensuring the safety of its customers by maintaining essential access to gas and electricity for heating and cooling.[51]

Addressing the concerns raised by Riley specifically, Staff maintains that the rates proposed in the Joint Proposal are both necessary and "reasonably calculated to allow the Company to recover prudent costs, while providing stakeholders an opportunity to earn a reasonable return."[52] Staff notes that the Q3 Quarterly Report upon which Riley relies was not entered into the record, addresses a time period that is different than that at issue in these proceedings and, in any event, does not

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[48] Company Post-Hearing Brief, p. 8; Company Post-Hearing Brief, pp. 4-6; Staff Post-Hearing Reply Brief, pp. 2-3.

[49] Staff Reply Statement in Support, p. 2.

[50] Id., p. 5.

[51] Id.

[52] Staff Post-Hearing Brief, p. 3.

solely concern the overall sufficiency of the Company's revenues and rates, as Riley claims. Instead, the Q3 Quarterly Report is a combined report for CH Energy Group and Central Hudson, detailing both companies' financial status as of September 30, 2024. Staff further notes that the description of the Company's financial status in the Q3 Quarterly Report is predicated, in part, on anticipated Commission action on the Company's requested rate increase in these proceedings.[53] Staff explains that the challenged statements are not contradictory because it is possible for the Company to have adequate cash available for short-term and long-term needs without a rate increase, while still facing the possibility of deteriorating financial integrity that would be reflected in its financial metrics and would eventually lead to credit downgrades for the Company and increasing cost of debt, which would be borne by ratepayers.[54]

The increases in revenue requirement contained in the Joint Proposal, while significant, are considerably reduced from the Company's original proposals as updated through rebuttal testimony, compare favorably to the likely results of a litigated outcome, and are the reasonable product of compromise among the parties. The increases will fund, among other things, capital projects required to upgrade aging infrastructure, customer protection initiatives, improvements to cybersecurity, and gas safety programs, and are consistent with the State's climate-related goals. Although we recognize that the rate increases may present a hardship for some ratepayers, we find

[53] Staff Post-Hearing Reply Brief, p. 3; Q3 Quarterly Report, pp. 15, 23. The 2025 Q1 Quarterly Financial Report, which was also not entered into the record, contains similar language to the 2024 Q3 Quarterly Report and is also predicated on Commission action in these rate proceedings (p. 13), does relate only to the Company.

[54] Staff Post-Hearing Reply Brief, at p. 3.

that the manner in which revenues will be collected – specifically, rates are mitigated and levelized over the three-year term of the rate plan through use of regulatory liabilities and the increases associated with the make-whole provision will be collected over the balance of RY1 and RY2 – will serve to ameliorate the rate impacts to some extent. As Staff notes, the proposed enhancements of the Company's EAP should help to limit – and in some cases, eliminate – for eligible customers the rate plan's resulting bill impacts. The increases appropriately balance affordability concerns with the Commission's obligation to ensure that the Company has adequate revenue to deliver safe and reliable service, will be able to meet the regulatory and statutory requirements imposed on it, and is able to provide a reasonable return to its investors. Moreover, many elements of the revenue requirement represent a compromise of various litigated positions and cannot be evaluated individually without the necessary context of the overall rate plan. Therefore, we reject CLP's and Shrestha's generalized objections to the revenue requirement set forth in the Joint Proposal.

We further reject Riley's contention that there is no evidence to support a finding that the Company requires any rate increase at all. The record soundly refutes that claim, as detailed at length in the remainder of this Order. In addition, Riley's allegation that the Company has acted in bad faith by misleading ratepayers and the Commission regarding its financial status is likewise meritless. Even if we were to consider the language in the quarterly financial reports – despite the fact that they were never entered into the record and one report was referenced for the first time in a Post-Hearing Reply Brief – we would find that the boilerplate language used in the reports presents no conflict with any position taken by the Company in these proceedings. As Staff explained, the quarterly reports anticipate Commission action in these proceedings and it is possible for a Company to have adequate cash available for foreseeable future needs without a rate increase, while still facing the possibility of decreased access to credit and capital markets and deteriorating financial integrity absent that increase. In any event, as Riley acknowledges, ratemaking is a forward-looking process,[55] and the rates proposed in the Joint Proposal are intended to maintain the Company's financial integrity for the three-year period commencing July 1, 2025, while the rates established in the 2024 Rate Order were designed to adequately support the Company's financial and operational needs as supported by the record compiled in the prior rate case proceeding. The proof in that case was primarily focused on analyses based upon forecasted costs over a future one-year period, i.e., until June 30, 2025. In any event, the establishment of a rate plan does not foreclose a utility from filing for a future increase in rates should it believe that the continued provision of services under the existing plan would not provide it with adequate financial stability to sustain its operations in a safe and reliable manner. Further, any time a utility files for an increase in revenue the burden of proof rests on the utility to demonstrate to the Commission's satisfaction that the increases are necessary.[56] Here, we find that on the record before us the opposing parties fail to justify upsetting the balance achieved by the Signatory Parties in negotiating the Company's future revenue requirements during the term of the Joint Proposal.

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[55] Riley Post-Hearing Reply Brief, p. 3 and n 4.

[56] Hearing Transcript, pp. 88-103.

3. Specific Rate Drivers

On the record submitted to the Commission, the Signatory Parties represent that the major drivers of the Joint Proposal's revenue requirement increases are funding for capital projects necessary to replace or upgrade aging and obsolete infrastructure, as well as depreciation expense, property taxes, and additional funding for labor and information technology systems related to the Company's ability to protect against and respond to cybersecurity threats.[57] Specific rate drivers that were or remain in significant dispute among the parties are addressed below.[58]

Labor and Compensation

The Joint Proposal reflects a labor headcount of 1,339 full-time employees (FTEs), an increase of 19 FTEs over what was allowed in the 2024 Rate Order but five fewer FTEs than requested by the Company in its filing.[59] The requested increase included 20 cybersecurity FTEs, which was reduced to 15 FTEs in the Joint Proposal to balance the Company's efforts to implement a cybersecurity operations center with both the Company's need to back-fill other cybersecurity positions lost to attrition and Staff's concerns about the Company's ability to effectively use new information technology employees as they are on-boarded and

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[57] Staff Statement in Support, Attachment B; Company Statement in Support, p. 13.

[58] The replacement of Leak Prone Pipe, which is challenged by both CLP and Shrestha, is addressed in the Performance Metrics section of this Order.

[59] Staff Statement in Support, pp. 26-27; Hearing Exhibit 149 (Company Revenue Requirement Panel Testimony), p. 13; Hearing Exhibit 176 (Company Workforce Compensation and Benefits Panel Exhibit WCBP-3).

trained.[60] In addition, the Joint Proposal reflects the Company's agreement to Staff's recommendation that its labor distribution projection reflect a three-year average, rather than the distribution in the historical test year, resulting in further savings.[61]

The Joint Proposal also reduced, from 4.5% to 4.0%, the wage escalation factor proposed for the Company's executive and non-executive management employees using the latest salary budget forecast from WorldatWork, a non-profit human resources association and compensation authority for professionals and organizations focused on compensation, benefits and total reward.[62] CLP argues that the 4.0% salary increase, which was recommended by Staff in its initial testimony, is too high for the Company's managers because a 4.0% raise was approved in the 2024 Rate Order, the increase is out of line with inflation, customers are already struggling to pay the rates approved in the 2024 Rate Order, and the Company's managers should not be rewarded in light of the Company's inadequate customer service and its continuing billing issues.[63]

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[60] Hearing Exhibit 310 (Staff Accounting Panel Testimony), p. 21; Hearing Exhibit 422 (Public Redacted Staff Security Panel Testimony), pp. 24-30.

[61] Staff Statement in Support, pp. 26-27; Hearing Exhibit 310 (Staff Accounting Panel Testimony), pp. 27-29. See 2024 Rate Order, p. 19.

[62] Staff Statement in Support, pp. 26-27; Hearing Exhibit 310 (Staff Accounting Panel Testimony), pp. 11-12, 25-26. The Joint Proposal also reduced the wage escalation factors from 4.5% to 2.8% for temporary employees and 3.6% to 3.0% for union employees. Hearing Exhibit 304 (Workforce Compensation and Benefits Panel Rebuttal Testimony), pp. 7-10.

[63] CLP Statement in Opposition, p. 7.

As explained in the 2024 Rate Order, the WorldatWork forecast is a source upon which Staff normally relies.[64] That Order rejected the argument that "generalized rate pressures" and the Company's "billing issues" warrant a deviation from reliance on the WorldatWork forecast, noting that the rate pressures upon the Company's customers do not differ markedly from those in other post-COVID-19 rate proceedings, no link has been established between the managerial class of employees and the Company's billing issues, and an independent monitor determined that the Company had resolved its billing issues.[65] Beyond anecdotal reports of continuing billing issues[66] and its generalized allegation that the Company's managers bear ultimate responsibility for its customers' troubles, CLP neither presents evidence calling into question the findings in the 2024 Rate

[64] 2024 Rate Order, p. 22.

[65] Id., p. 21; Case 22-M-0645, Proceeding on Motion of the Commission Concerning Central Hudson Gas & Electric Corporation's Development and Deployment of Modifications to its Customer Information and Billing System and Resulting Impacts on Billing Accuracy, Timeliness, and Errors, Order Adopting Terms of Settlement Agreement (issued June 20, 2024), p. 7. In addition, as described in the Customer Service section of this Order, the Joint Proposal contains several provisions to monitor the Company's customer service performance and continues the existing Customer Service Performance Indicators incentive mechanism, which establishes negative revenue adjustments that incentivize the Company to resolve customer complaints, including those related to billing issues.

[66] Without calling into question the struggles of individual customers with billing issues, we note that, as reported in the Company's Customer Service Performance Indicator reports, during the first three months of 2025, the percent of adjusted bills or corrected bills during the first was 1.45%, which reflects a 46% reduction in adjusted bills from 2024. The Joint Proposal requires the Company to continue making significant investments in its billing processes to continue the reduction corrected or adjusted bills (Hearing Exhibit 510 (Response to IR ALJ-6)).

Order nor articulates a rationale for departure from the approach taken in that Order.[67]

We further note that that management wage escalation rates are not "rewards" or merit-based increases, as CLP claims; rather, they are meant to capture forecasted changes in labor market dynamics.[68] Although the Company proposed that it also be permitted to recover a portion of its executive short-term incentive compensation as a component of a total executive compensation package, the Joint Proposal reflects no allowance for executive incentive compensation in RY1.[69] As explained in the Deferrals Section of this Order, the Joint Proposal provides for deferral treatment until the Company completes recommendation 2.7 from its most recent management and operations audit in Case 21-M-0541.[70]

Arrears

Both CLP and Shrestha argue that the Joint Proposal fails to fully acknowledge or adequately respond to the Company's historic levels of uncollectible bills and arrears. CLP argues that the Company's issuance of inaccurate bills has contributed to the Company's inordinately high level of arrears

[67] See Matter of Charles A. Field Delivery Servs., 66 N.Y.2d at 516-517, supra.

[68] Staff Reply Statement in Support, p. 6.

[69] Staff Statement in Support, pp. 29-30.

[70] Joint Proposal, p. 15. Recommendation 2.7 provided that the Company's management should set Team Goal targets, which determine the payouts for its incentive compensation for managers and executives, to require continuous improvement, rather than rewarding those employees for achieving minimum performance levels set in rate plans (See Case 21-M-0541, Central Hudson – Comprehensive Management and Operations Audit, Order Approving Implementation Plan with Modification (issued March 15, 2024), pp. 8-9).

and urges the moderation or reduction of rates.[71] Shrestha urges the Commission to develop a plan to implement its 2016 goal to cap utility bills at 6.0% of household income, asserting that goal could be achieved by near-to-full enrollment in the EAP.[72]

The Joint Proposal reflects a forecast of uncollectible expense based on bad debt factors of 1.6% for electric and 1.9% for gas, a significant reduction from the 2.9% for electric and 3.5% for gas forecast by the Company.[73] In addition, as Staff and the Company argue in response to CLP and Shrestha, the provisions of the Joint Proposal designed to boost enrollment in the Company's EAP – with a goal of enrolling at least 15,500 households by the end of RY1[74] – and the Company's agreement to waive finance charges associated with Deferred Payment Agreements will aid customers in arrears and assist in reducing the number of customers that go into arrears.[75] While we share the opposing parties' concern with the number of customers currently in arrears, which is a statewide problem, we note that the Commission recently adopted an enhanced EAP (EEAP) that will be open to customers earning below the State Median Income but currently ineligible for EAP benefits, in order to expand the number of households eligible to receive utility bill

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[71] CLP Statement in Opposition, pp. 6-7. CLP's additional arguments about the Company's Reconnection Charge are addressed in the Tariff-Related Matters section of this Order.

[72] Shrestha Statement in Opposition, pp. 3-4.

[73] Staff Statement in Support, p. 29.

[74] As of April 30, 2025, the Company had 13,598 EAP participants. Hearing Exhibit 526 (Response to IR ALJ-20).

[75] Staff Reply Statement in Support, pp. 14-15; Company Reply Statement in Support, pp. 10-11. The waiver of finance charges is discussed further in the Customer Service section of this Order.

relief.[76] The same order directed utilities to increase EAP budget caps from 2.0% to 2.5% of total annual revenues and to establish a separate EEAP budget cap of 0.5% of total annual revenues.[77] In addition, the DPS EAP Working Group is exploring arrears-related recommendations for consideration on a statewide basis.[78] We conclude that Shrestha's arguments regarding modifications to the EAP are more appropriately pursued on a statewide basis through the generic Energy Affordability Policy Proceeding in Case 14-M-0565, and that the concerns raised by CLP are adequately addressed by the Joint Proposal's enhancements to the Company's EAP and more stringent customer service metrics that will alleviate any continuing billing issues.

Fortis Overhead Allocation Methodology

Finally, CLP argues that the Joint Proposal lacks transparency regarding the Company's payments to its parent company, Fortis, Inc., and that the terms of the Company's financial obligations to Fortis are less than clear.[79] The Joint Proposal provides that, subject to the cost allocation requirements established in the Commission's Order authorizing

[76] Cases 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers and 23-M-0298, Matter of Budget Appropriations to Enhance Energy Affordability Programs, Order Adopting Enhanced Energy Affordability Policy and Directing Utility Filings (issued July 17, 2025).

[77] Id., p. 31.

[78] Staff Reply Statement in Support, p. 14.

[79] CLP Statement in Opposition, p. 11.

Fortis Inc.'s acquisition of the Company in Case 12-M-0192,[80] the Company will report any changes in the allocation methodology of Fortis overhead costs within 60 days after the revised cost allocation effective date.[81] The Company will also report any changes in the Fortis Overhead Allocation Methodology in its Annual Report of Affiliate Transactions filed on April 1 of each year pursuant to the Acquisition Order.[82] CLP notes that the Cost Allocation Guidelines referenced in the Acquisition Order do not mention "overhead" or allocation methodology and do not specify any concrete terms governing the Company's financial obligations to Fortis.[83]

The Company responds that the Cost Allocation Guidelines provide specific cost allocation methodologies and formulas for allocating costs of a parent holding company to its affiliates.[84] The Company maintains that the absence of the word "overhead" is irrelevant because that term is a shorthand reference for all holding company expenses identified in the Cost Allocation Guidelines that are subject to cost allocation

[80] Case 12-M-0192, Joint Petition of Fortis Inc. et al. and CH Energy Group, Inc. et al. for Approval of the Acquisition of CH Energy Group, Inc. by Fortis Inc. and Related Transactions, Order Authorizing Acquisition Subject to Conditions (June 26, 2013) (Acquisition Order), pp. 17-18, and Joint Proposal attached thereto, Attachment I, Standards of Conduct, pp. 9-10. See Case 96-E-0909, Matter of Central Hudson Gas & Electric Corporation's Plan for Electric Rate/Restructuring Pursuant to Opinion No. 96-12, Order Adopting Terms of Settlement Subject to Modifications and Conditions (issued February 19, 1998), attached Amended and Restated Settlement Agreement dated January 2, 1998, and Attachments H (Cost Allocation Guidelines) and I (Standards of Conduct).

[81] Joint Proposal, pp. 22-23.

[82] Id.

[83] CLP Statement in Opposition, p. 11.

[84] Company Reply Statement in Support, p. 15

between multiple subsidiaries – including expenses such as legal, accounting, and administrative services.[85] The Company argues that such costs are "fully transparent within the Company's revenue requirement workpapers submitted with the Company's initial filing, which were made available to all parties," reviewed by Staff in these proceedings, and were not subject to any discovery requests by CLP, despite their availability.[86]

Staff similarly asserts that CLP's argument "stem[s] from confusion on terminology related to costs or 'overhead' that Fortis, Central Hudson's holding company, allocates to" the Company.[87] Staff states that the "Joint Proposal simply reaffirms requirements from other orders and does not modify or limit the transparency of prior Commission requirements."[88]

The Joint Proposal continues the set of cost allocation standards adopted in the Acquisition Order,[89] which, when coupled with the relevant reporting requirements, provide Staff with the information needed to ensure that proper cost allocation procedures are followed. The Commission approved the provisions of the Fortis Overhead Allocation Methodology in the Company's last settled rate case.[90] Although CLP now appears to be proposing unspecified changes to the cost allocation procedures previously approved by the Commission, we note that, despite having the ability to conduct discovery and obtain

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[85] Id., p. 16.

[86] Id., p. 17.

[87] Staff's Reply Statement in Support, p. 10.

[88] Id., p. 11.

[89] Acquisition Order, pp. 17-18, Joint Proposal attached thereto, pp. 18-19 and Attachment I, pp. 9-10.

[90] Cases 20-E-0428 et al., supra, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan, Joint Proposal, pp. 34-35.

information about Fortis's overhead cost allocations in this case, CLP did not raise any issues in pre-filed testimony. CLP's failure to raise such issues is particularly notable given that the Company specifically stated in its initial testimony that it allocated Fortis administrative costs in setting its proposed revenue requirement for the Rate Year based on latest known annual estimates provided by Fortis for the 2024 through 2028 period.[91] Based on the foregoing, we conclude that CLP's arguments do not call into question the reasonableness of the Fortis Overhead Cost Allocation provision in the Joint Proposal or provide a basis for departure from our prior orders approving the Company's established cost allocation procedures.[92]

Cost of Service, Revenue Allocation, and Rate Design

1. Cost of Service

The Joint Proposal does not use or reflect a single embedded cost-of-service (ECOS) study sponsored by a party. Rather, the Signatory Parties agreed to cost-of-service provisions that reflect compromise among the settling parties.

However, the Joint Proposal requires the Company to include in its next rate filing additional, detailed narrative information and analyses related to its ECOS studies. This information includes an analysis of the rate structure resulting from parsing electric SC-13 into standard and high-load factor groupings.[93] To inform its analysis, the Company will convene a collaborative process with interested stakeholders prior to the end of RY1 and the Company will file a report before the end of

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[91] Hearing Exhibit 149 (Company Revenue Requirements Panel Testimony), p. 54.

[92] See Matter of Charles A. Field Delivery Servs., 66 N.Y.2d at 516-517, supra.

[93] Joint Proposal, p. 28.

RY2 that summarizes the potential solutions analyzed by the collaborative, as well as the positions of the participating stakeholders.

In addition, for its next rate case, the Company will conduct an analysis of a rate structure that would result from parsing gas SC-6 separately within the ECOS study.[94] Separate from the ECOS study, the Company also will include a load factor analysis of all non-residential gas customers taking service under SCs 2, 6, and 13 and, based on that analysis, the Company will include in the next rate case filing a proposal for modifications of the existing service classification structure or eligibility, with an estimate for implementation time and cost.[95] Finally, the Joint Proposal requires the Company to provide the parties in its next rate case its ECOS study model and supporting workpapers, including any engineering and accounting analyses, that it relied upon in supporting its proposed classification, allocation, and functionalization of costs.

These provisions of the Joint Proposal are not contested by any party and address concerns raised by various parties in their testimonies. We find the cost-of-service provisions to be a reasonable compromise among normally adversarial parties that fall within the expected outcomes of a fully litigated case. Further, the additional information that the Company will make available to parties in its next rate case will help those parties avoid confusion and will better inform the parties' understanding of the Company's ECOS models.

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[94] Id., p. 29.

[95] Id.

2. Revenue Allocation and Rate Design

The revenue allocation and rate design provisions of the Joint Proposal, found in Appendices O and P, are a result of extensive negotiations among the Signatory Parties. These provisions are not contested by any party.[96]

a. Electric

The Joint Proposal calls for increases to RY1 electric customer charges that are less than those initially requested by the Company.[97] Specifically, electric residential (SC-1) and small commercial (SC-2 Non-Demand) customers will see an increase of $1.00 in RY1, as opposed to the $2.00 increase requested by the Company.[98] For electric large non-residential customers, who are primarily in SC-3 and SC-13, the customer charges for those service classes will increase by the specified amounts each rate year, and the remainder of the revenue required to be recovered from those customers will be collected through an increased demand charge.[99]

The changes to electric customer charges are the product of negotiation that consider the positions of various parties, including UIU, which proposed no increase to SC-1 customer charges in RY1, as well as MI and Walmart, each of whom

[96] CLP generally argues that the proposed "fixed" "delivery costs" produce rates that are unaffordable for "residential customers who are not enrolled in an affordability program." (CLP Statement in Opposition, p. 5). But CLP does not provide specific arguments regarding the provisions in the Joint Proposal regarding cost-of-service, revenue allocation, and rate design.

[97] Hearing Exhibit 79 (Company Forecasting and Rates Panel Testimony), pp. 51-53.

[98] Joint Proposal, Appendix O, Sheet 2. The customer charges for SCs 1 and 2 (Non-Demand) will increase by $1.50 in RY2 and $2.00 in RY3.

[99] Joint Proposal, p. 30, Appendix O.

proposed different customer charges for SC-3, SC-13 (Primary), and SC-13 (Transmission), among other service classes. The Joint Proposal also addresses Walmart's concern that the delivery energy charges for SC-2 (Demand-Secondary) and SC-2 (Demand-Primary) remain at the current level to align cost recovery with cost of service for those customers, like Walmart, that take only delivery service from the Company.[100] MI expressed similar concerns about the Company's proposed rate design for SC-3 and SC-13 (Transmission). The terms of the Joint Proposal thus reflect an allocation of non-customer charge revenue increases as 100% demand and 0% energy for SC-2 (Demand-Primary), SC-2 (Demand-Secondary), SC-3, and SC-13 (Transmission).[101]

b. Gas

For gas, the Joint Proposal provides for lower RY1 customer charge increases than initially proposed by the Company. For RY1, mass-market customers (SCs 1, 2, 6, 12, and 13) will see a customer charge increase of $1.00 rather than the $2.00 increase originally requested by the Company.[102] For sub-classes of SC-11, the Joint Proposal includes various decreases to the customer charges to better align those charges with cost-of-service evidence.[103]

Notably, the Joint Proposal implements the final year of the phase-out of gas declining block rates, effective July 1, 2025, implements the final year of the phase-out of the high-

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[100] Walmart Statement in Support, pp. 3-4.

[101] According to MI, absent this outcome, it would not have supported the Joint Proposal (MI Statement in Support, pp. 13-14).

[102] The customer charges for SC-1 and SC-12 will increase by $1.50 in RY2 and $2.00 in RY3. Joint Proposal, Appendix O, Sheet 10.

[103] Joint Proposal, Appendix O, Sheet 10. See Staff Statement in Support, p. 63.

volume discount for SC-6 customers, and eliminates SC-15 (Distributed Generation – Commercial and Industrial) and SC-16 (Distributed Generation – Residential).[104] These phase-outs are important to improve price signals of gas delivery rates and support the State's climate-related goals. CLP, which otherwise opposes the Joint Proposal, states that it "strongly supports" the elimination of both declining block rates and the high-volume discount service classes.[105]

Finally, as part of its next rate case, the Company will include exhibits that show indexed class rates of return both before and after allocation of the proposed electric and gas revenue requirements.[106] This information was initially requested by MI and its required production in the Company's next filing was initially opposed by the Company.[107]

The electric and gas revenue allocation provisions are a reasonable product of negotiation among the Signatory Parties and gradually adjust customer charges to more faithfully align with each customer class's true cost of service, while being mindful of the impact the changes will have on customers' bills. The proposed changes to rate design also are reasonably crafted to better align with cost-of-service evidence and reflect movement to eliminate intra-class subsidies. We therefore find

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[104] Joint Proposal, p. 30, Appendix O. As a result of the phase-out of the discount for SC-6 customers, all SC-6 customers will be assessed at the same volumetric rate. According to the Company, SC-15 and SC-16 were offered to customers with installed gas-fueled generating equipment and no customers have taken service under those classes and none are expected to in the future. See Company Statement in Support, pp. 24-25.

[105] See CLP Statement in Opposition, pp. 10-11.

[106] Joint Proposal, p. 30.

[107] See Hearing Exhibit 471 (Testimony of Jonathan Ly), p. 4 and Hearing Exhibit 200 (Company Cost of Service Panel Rebuttal Testimony), pp. 29-30.

that both the revenue allocations and rate designs proposed in the Joint Proposal are in the public interest.

c. Gas Capacity

In its initial testimony, Staff raised concerns about data received from the Company indicating that the Company had been charging its gas sales customers and gas transportation customers, including retail access customers,[108] different rates for capacity.[109] Specifically, the Company calculated its weighted average cost of capacity (WACOC) each month and assigned the April cost to both sales customers and retail access customers. However, while the cost for retail access customers remained the same for 12 months, the Company's sales customers were paying a monthly variable rate.[110] According to Staff, it is inequitable for sales customers to pay a monthly variable rate while retail access customers are charged a stable rate over an entire year. In rebuttal, the Company denied that an inequity existed and further claimed that no inequity would occur because the WACOC rate can be reset for retail access customers if the monthly system average cost of capacity varies by more than 5.0%.[111]

The Joint Proposal includes a provision that requires the Company, within a month of the effective date of this Order, to set the capacity rate paid by retail access customers to be equal to the capacity rate paid by sales customers.[112] In

[108] The term "retail access customers" includes energy service companies, or ESCOs.

[109] Hearing Exhibit 384 (Staff Gas System Planning and Reliability Panel Testimony), pp. 32-35. See Hearing Exhibit 242 (Company Exhibit FRP-2R).

[110] Id.

[111] Hearing Exhibit 240 (Company Forecasting and Rates Panel Rebuttal Testimony, pp. 17-19.

[112] Joint Proposal, p. 61.

addition, the Joint Proposal requires the Company to initiate a collaborative process with interested parties before the end of 2026 to evaluate the capacity available for release under the Company's retail access program.[113] This collaborative will explore potential differences between supply pipelines that are released to retail access marketers for SC-6, SC-12, and SC-13 customers participating in the retail access program compared with pipelines used by the Company on behalf of firm sales customers. The Company will then report its findings to the Commission before the end of RY2, including any proposed changes to its Gas Transportation Operating Procedures Manual.[114] This provision is reasonable and in the public interest because it aims to ensure that the capacity charges for the Company's sales customers are not higher than the capacity charges for customers participating in the Company's retail access program.

Capital Structure and Rate of Return

Federal and State courts have long shaped ratemaking, creating the principles, which are reflected in the applicable statutes, that bind regulatory bodies in determining just and reasonable utility rates.[115] As stated above, utility regulators must balance customer interests against the interests of utility investors, while also ensuring that utilities have sufficient revenue to cover operating expenses and capital costs.[116] Courts have ruled that a fair return to equity owners is one that is both commensurate with returns on investments in other

[113] Id., pp. 61-62.

[114] Id.

[115] See PSL §65 (1).

[116] Federal Power Commn. v. Hope Natural Gas, 320 U.S. 591, 603 (1944); Matter of St. Lawrence Gas Co. v. Public Serv. Commn., 54 A.D.2d 815 (Third Dep't 1976).

enterprises sharing corresponding risks and sufficient to assure confidence in a utility's financial integrity, allowing the utility to maintain its credit and attract further investment capital.[117] However, the courts have also made clear that only a fair opportunity to earn a return must be provided, not a guarantee of achieving it, and that the responsibility to manage utility operations efficiently to achieve profitability, as well as the risk of failure to do so, rests on the utility.[118] These basic principles, grounded in the Due Process provisions of the Federal Constitution, guide our analysis of the parties' disputes on the Company's capital structure and rate of return.

1. Capital Structure

In general, utilities finance the bulk of their operations through a mix of equity investment and debt obligations.[119] The equity component costs ratepayers more than the debt component.[120] Thus, the more equity needed to fund operations relative to debt, the higher customer rates will rise. However, as the proportion of a utility's rate base increases in long-term debt obligations, so does the utility's financial risk.[121] As such, regulators generally favor a relatively equal division of equity and debt obligations, which benefits customers by providing financial stability. Here, the

[117] Hope Natural Gas, 320 U.S. at 603.

[118] Matter of Abrams v. Public Serv. Commn., 67 N.Y.2d 205, supra; St. Lawrence Gas, 54 A.D.2d at 815 (citing Federal Power Commn. v. Natural Gas Pipeline Co., 315 U.S. 575, 590 (1942)).

[119] Hearing Exhibit 351 (Staff Finance Panel Testimony), pp. 12-13.

[120] Id., p. 13.

[121] Id.

Joint Proposal continues the 48% equity ratio established by the Commission in the 2024 Rate Order.[122]

2. Cost of Common Equity

The ROE is a calculated percentage applied to the equity-funded component of a utility's rate base, as measured by the applied equity ratio. The purpose of setting the ROE is to provide the Company's investors with an opportunity to earn a return on their invested capital, which facilitates the utility's ability to continue to attract sufficient investment capital so that its operations are not funded completely by debt obligations. In short, a rate plan's ROE is the numerical representation of the constitutionally required fair opportunity for the Company's investors to earn a return on the capital used in creating and maintaining the infrastructure dedicated to public utility service.[123]

In the Commission's 1991 generic proceeding assessing its financial regulatory policies and practices, the co-facilitators of that proceeding issued a Recommended Decision analyzing stakeholder proposals, supporting evidence, and comments regarding financing methodologies and issues.[124] In the years since, the Commission has explicitly incorporated several elements from that Decision into its preferred methodology for computing a utility's allowed ROE.[125]

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[122] Joint Proposal, p. 23; 2024 Rate Order, pp. 70-71.

[123] Smyth v. Ames, 169 U.S. 466, 546 (1898) (stating, "The corporation may not be required to use its property for the benefit of the public without receiving just compensation for the services rendered by it."). See Matter of Abrams v. Public Serv. Commn., 67 N.Y.2d 205, 212, supra.

[124] Case 91-M-0509, Generic Finance Methodology Proceeding, Recommended Decision (issued July 19, 1994).

[125] Case 16-G-0257, NFG - Rates, Order Establishing Rates for Gas Service (issued April 20, 2017), p. 54.

In reliance on that preferred methodology, the Signatory Parties agreed in the Joint Proposal to a ROE of 9.5% for all three rate years, continuing the 9.5% ROE that was approved in the 2024 Rate Order.[126] Riley asserts that a ROE of 9.5% is not supported by the Record and challenges the Signatory Parties' claim that the Joint Proposal appropriately balances the interests of the Company's ratepayers and investors, specifically focusing on the Company's parent company – Fortis – and Fortis's potential return on its investment in the Company.[127] Specifically, Riley argues that the Commission cannot conclude that the Joint Proposal "strikes a fair balance among the interests of ratepayers and investors and the long-term soundness of the utility," as required by the Settlement Guidelines,[128] because the Company did not adequately develop the record with respect to the interests of the Company's ultimate investor – Fortis.[129] Riley notes that the Acquisition Order provides that Staff be given "access to any books and records of Fortis and its affiliates that Staff might deem necessary to determine whether the rates and charges of Central Hudson are just and reasonable."[130] Because the Commission deemed such access "vital to ensuring ratepayers are protected,"[131] Riley argues that Fortis's financials must be considered in the context of this rate case in order to determine whether the Joint Proposal appropriately balances ratepayer and investor

[126] Joint Proposal, p. 23.

[127] Riley Post-Hearing Brief, pp. 5-10; Riley Post-Hearing Reply Brief, pp. 6-9. Riley's other arguments have already been addressed above and will not be repeated in detail here.

[128] Settlement Guidelines, p. 30.

[129] Riley Post-Hearing Brief, pp. 5-7; Riley Post-Hearing Reply Brief, pp. 2.

[130] Acquisition Order, p. 17.

[131] Id., p. 37.

interests.[132] Because the Company has provided an average income to common shareholders of approximately $80 million annually over the last three years, which amounts to approximately 5-6% of Fortis's overall profits, Riley argues that the Commission must assess whether that shareholder income should be returned to ratepayers.[133] In that regard, Riley concedes that an ROE of 9.2% – as recommended by Staff in it is initial testimony – is supported by the record, but asserts that is the very upper bound that the Commission should accept.[134]

Staff responds that, in agreeing to an ROE of 9.5% in the Joint Proposal after initially recommending a 9.2% ROE, it considered litigation risk, changes in the financial markets since Staff filed its initial testimony, the additional business and financial risks inherent in a multi-year agreement, and the Commission's recent approval of the same or similar ROEs for other utilities with risk profiles similar to that of the Company.[135] Staff maintains that, in determining the appropriate ROE, it is appropriate to consider the utility as a standalone entity if it is adequately ringfenced and that a review of Fortis's overall financial condition – including its investments in entities other than Central Hudson – is simply not relevant.[136] Staff further explains that the Acquisition Order does not mandate that Commission or Staff review of all Fortis's books and records in every rate case, regardless of their relevance, and that review of Fortis's books was not required

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132 Riley Post-Hearing Brief, pp. 7-8.

133 Staff Post-Hearing Reply Brief, pp. 6-7; Riley Post-Hearing Reply Brief, pp. 6-7.

134 Riley Post-Hearing Reply Brief, pp. 8-9.

135 Staff Post-Hearing Brief, p. 4; Staff Post-Hearing Reply Brief, p. 4.

136 Staff Post-Hearing Reply Brief, pp. 4-5.

here in the absence of proof of any aberrations in the Company's manner of allocating costs to Fortis.[137]

The Company responds that a 9.5% ROE is reasonable because it represents Staff's recommended 9.2% ROE with a risk-based premium added to account for the fact that the Joint Proposal involves a multi-year rate case settlement.[138] Because it was the product of settlement and not derived from any specific methodology, the Company maintains that Riley's concerns about any particular model that the Company may have used to calculate its initially requested ROE are not relevant.[139] The Company further argues that the Settlement Guidelines, in requiring a balancing of, among other things, investor and ratepayer interest, do not require consideration of the other investments of utility shareholders.[140] Similarly, the Company argues that the Acquisition Order, in requiring that the Commission have ready access to Fortis's books and records, was addressing transactions between Central Hudson and its affiliates, rather than suggesting that Fortis's overall earnings, which are based primarily on its other investments, are relevant to setting rates for the Company.[141]

We reject Riley's challenges to the ROE. As an initial matter, there is no validity to the claims raised by Riley regarding the appropriateness of assessing the Company's financial needs on a stand-alone basis, separate from its upstream ownership. Staff agrees with the Company's position that credit ratings agencies provide their rate analyses of the

[137] Id., p. 5.

[138] Company Post-Hearing Brief, p. 9.

[139] Id., p. 8.

[140] Company Post-Hearing Reply Brief, p. 7.

[141] Id., p. 8.

Company on a stand-alone basis. Thus, Staff also evaluates the Company’s rate of return as an individual entity.[142] We agree with Staff that, because the record demonstrates that sufficient ring-fencing provisions are in place at the Company, no further in-depth review of the upstream ownership of the Company is required to adopt a rate plan for the Company at this time.[143]

Moreover, as explained above, the Commission is legally obligated to provide each of the Company’s investors with an opportunity to earn a return on their investment capital; that opportunity necessarily extends to the Company’s upstream corporate owners. The proposed ROE in the Joint Proposal satisfies this obligation. As Staff and the Company explain, the ROE was calculated by taking Staff’s initially recommended ROE of 9.2% – which Riley concedes is supported by the Record here – and adjusting it to take into account the risk and uncertainties stemming from a multi-year settlement. In our view, that calculation has resulted in a reasonable ROE. Given Riley’s concession that the 9.2% ROE is supported by the Record, no further review of Fortis’s books and records could be relevant here.

Furthermore, we find that the ROE supports the interests of ratepayers by balancing the financial profile of the Company between debt and equity obligations to provide the most stable and cost-effective funding for the Company’s utility services. As Staff notes, it appears that Riley misunderstands the requirement in the Settlement Guidelines that a Joint Proposal fairly balance the interest of investors and

[142] Hearing Transcript, pp. 120-122, 153-157.

[143] As Staff notes, the conclusion on adequate ring-fencing means that sufficient safeguards are in place to isolate the utility from the influence of the upstream ownership (Staff Post-Hearing Brief, pp. 5-6).

ratepayers. The Settlement Guidelines address balancing affordability concerns against utility shareholders' long-recognized right to earn a reasonable return on investment;[144] the Guidelines in no way compel a broad assessment of the financial situation of those shareholders.[145] We conclude that the record in these cases demonstrates that Staff appropriately conducted a thorough review of the Company's finances separate and apart from those of Fortis to arrive at a reasonable ROE and overall revenue requirement.

Shrestha also generally challenges the ROE as too high and not in the customer's interests and, therefore, not in the public interest. Shrestha claims that the inclusion of high ROEs in utility rate plans is the cause of excessive unwarranted capital investments that have caused the rates for investor-owned utilities to outpace inflation by 49%, whereas publicly owned (i.e., government nonprofit) utility rates have increased at a rate of 44% less than inflation.[146] Shrestha requests that the Commission reduce the allowed ROE to 9.0%, which is the minimum ROE the Company claimed in testimony that it would need to avert a credit downgrade. Shrestha additionally requests that the Commission require the Company to submit a shareholder-funded study to verify the Company's claim that the costs to customers resulting from a credit-rating downgrade would exceed the costs to customers associated with maintaining a higher credit rating. Finally, Shrestha urges the Commission to conduct a study to determine whether cost savings would result

[144] Hope Natural Gas, 320 U.S. at 603, supra.

[145] Staff Post-Hearing Reply Brief, at 4.

[146] Shrestha Statement in Opposition of the Joint Proposal, pp. 2-3.

if the Company were replaced with a not-for-profit, state-run corporation.[147]

As it did in answering Riley's arguments, Staff responds that the Joint Proposal's 9.5% ROE reflects the use of Staff's methodology updated to existing conditions at the time of the agreement. In addition, Staff cites to several recent Commission orders adopting a similar ROE, which – while not precedential – provide evidence of consistency in approach and evaluation.[148] Staff also notes again that the Commission is obligated to provide a utility with the opportunity to earn a return that is commensurate with the return of other companies with similar risk profiles, and that, in calculating a fair ROE, Staff incorporates a proxy group of similarly situated companies in its analysis.[149] Staff argues that it is not appropriate to consider any comparison of publicly owned utilities in setting the ROE of an investor-owned utility because publicly owned utilities do not share the same attendant risks of operations and they have access funding unavailable to investor-owned utilities.[150]

We agree. On review of the record submitted in these cases, we determine that the Joint Proposal's ROE is consistent with the Staff methodology elements that have been cited as the Commission's preference and based on an appropriate proxy group of similarly situated companies. We are not persuaded that, in the overall context of a negotiated settlement, the proposed ROE is so egregious or contrary to the public interest that the

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[147] Id., p. 3.

[148] Staff Post-Hearing Brief, p. 3.

[149] Staff Reply Statement in Support of the Joint Proposal, p. 7, see Staff Post-Hearing Brief, pp. 3-4.

[150] Id., pp. 4-5.

Commission should modify it, thereby upsetting the careful balance reached by Signatory Parties.

3. Earnings Sharing Mechanism

The Joint Proposal contains an Earnings Sharing Mechanism (ESM) to protect customers from excess earnings.[151] Under the terms of the ESM, the Company will be allowed to retain any earnings it attains of up to 10.0%. Earnings greater than 10.0% but less than 10.5% are shared equally between the Company and customers. Earnings between 10.5% and 11.0% are shared 75.0% to customers and 25.0% to the Company. Lastly, earnings greater than 11.0% will be shared 90.0% to customers. As the Commission has found, such a provision provides customers, particularly during multi-year rate plans, with a share of efficiencies realized by the utility while providing the utility an incentive to find such efficiencies.[152] This provision supports our finding that the Joint Proposal, as a whole, is in the public interest.

Capital Expenditures, Reconciliations, and Deferrals

1. Capital Expenditures

Appendix E to the Joint Proposal provides agreed-upon forecasted capital expenditures for calendar years 2025 through 2028.[153] The Joint Proposal provides for an electric capital investment of approximately $154.83 million in RY1, $156.77 million in RY2, and $159.61 million in RY3. Programs supported by these investments include CLCPA Phase 1 projects that will increase transmission and distribution capacity by approximately

[151] Joint Proposal, pp. 23-24.

[152] Case 23-G-0627, NFG - Rates, Order Adopting Terms of a Joint Proposal and Establishing Gas Rate Plan with Minor Modifications (issued December 19, 2024), pp. 34-35.

[153] Joint Proposal, Appendix E, Schedule A.

500 MW, facilitating additional renewable interconnections; Storm Hardening projects that improve reliability on the Company’s worst performing circuits; and projects addressing aging infrastructure, maintaining system reliability, new business growth, resiliency, and regulatory compliance. Investments in this area will be crucial for supporting the State’s electrification goals.[154]

The Joint Proposal provides for a gas capital investment of approximately $84.56 million in RY1, $79.17 million in RY2, and $79.66 million in RY3. These investments will support the leak prone pipe (LPP) removal targets so that all LPP will be replaced in 2028, as well as continued maintenance and improved reliability of the existing gas distribution system, such as replacements of transmission pipe and regulator stations.[155] The Joint Proposal provides for common capital investment of approximately $90.93 million in RY1, $83.98 million in RY2, and $67.72 million in RY3. Investments under this category include completion of the Company’s Training Academy - Annex (indoor) space project, which will be used to provide hands-on training and development of FTEs in various departments; work on the Company’s Training Academy – Academy project, which will provide classroom and meeting spaces for employee training, development, and meetings; and the replacement of outdated software and applications for

[154] The annual electric capital expenditure budget listing all electric capital projects is contained in Appendix E, Schedule B.

[155] The annual gas capital expenditure budgets listing all gas capital projects is contained in Appendix E, Schedule C.

improved efficiency, cybersecurity for customers and infrastructure, and improved work product.[156]

The Company will continue to file with the Secretary to the Commission by July 1 of each year its five-year capital investment plan. The Company also will continue to file with the Secretary by March 1 of each year a report on its capital expenditures during the prior calendar year.[157] The annual report will discuss any substantive changes to a project and will include an explanation of any cost variance between an approved work order authorization and an actual expenditure greater than 10% for any single project identified in the Company's Major Capital Project Report. As illustrated in Appendix D, the Company will prepare its capital budget by project or program category, rather than as a single total expenditure.

The Company will file quarterly capital variance reports within 45 days after the end of each quarter, except for the fourth quarter when the Company will submit the quarterly and annual reports by March 1 of the following calendar year.[158] For physical and cybersecurity projects, the Company will file quarterly reports indicating (1) when physical cybersecurity projects reach significant milestones, are merged with other projects, or are discontinued; and (2) when significant changes are made to cybersecurity-related FTEs.[159] The Joint Proposal also implements a requirement for the Company to file, twice a

[156] The Information Technology (IT) common capital budgets listing all IT capital projects is contained in Appendix E, Schedule E. The non-IT common capital budgets listing all non-IT capital projects is contained in Appendix E, Schedule D.

[157] Joint Proposal, p. 10.

[158] Id., p. 11.

[159] Id.

year, a status and update report on project spending and project schedules for each physical and cybersecurity project and program. The report will also highlight and explain significant changes to those projects and programs.[160]

The record establishes that the participating parties in these proceedings thoroughly examined the Company's proposed capital programs and associated expenditures. The budgets reflected in the Joint Proposal fall within the range of possible outcomes that could have resulted following a fully litigated case and represent a reasonable compromise that will allow the Company to continue to provide safe and reliable service to its customers.[161] The capital investments will allow the Company to replace aging and obsolete infrastructure, retire LPP and leak-prone services (LPS) within its service territory, improve customer service and billing processes, and update its cybersecurity systems. In addition, the capital reporting requirements require a more detailed presentation of the Company's capital budgets,[162] which will allow Staff and the Commission to better track the Company's projects, expenditures and capital program needs.

2. Deferrals

The Joint Proposal continues the use of deferral accounting for several expense elements, modifies some existing deferral mechanisms, and includes new deferrals.[163] Appendix F to the Joint Proposal contains a comprehensive list and

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[160] Id., p. 11 and n. 15; Hearing Exhibit 520 (Response to IR ALJ-14, Attachment 1)

[161] See Staff Statement in Support, pp. 32-39.

[162] See Hearing Exhibit 520 (Response to IR ALJ-14, Attachment 1).

[163] See Hearing Exhibit 518 (Response to IR ALJ-13, Attachment 1) (identifying existing, modified and new deferrals).

explanation of each deferral. Noteworthy deferral mechanisms are discussed below.

a. Call Center Legislation

The Joint Proposal adds a deferral mechanism in response to the enactment of Chapter 107 of the Laws of 2025, which amended PSL §65(13), to become effective June 19, 2025, to require gas and electric corporations to have customer service calls answered within the utility's service territory, except under certain circumstances. The statute, which is the subject of federal litigation,[164] would impact the Company's current call center staffing location and operations, which are outside the state. Because the incremental cost to comply with the amended law currently is uncertain, the Joint Proposal provides for deferral treatment for the resulting incremental costs of up to $7.5 million per Rate Year and 50% recovery of expenses beyond that amount, up to a total deferral of $8.5 million per Rate Year.[165]

The deferral mechanism is appropriate to address the currently unknown costs and the amount is reasonable, because it would be used to cover incremental costs including labor, training, equipment, and office space. Moreover, the partial recovery of additional costs would encourage the Company to limit expenses. The Joint Proposal also imposes additional reporting requirements associated with the call center legislation, which we discuss later in the Customer Service section.

[164] National Fuel Gas Distribution Corp. v. Christian, Case No. 1:25-cv-00525 (N.D.N.Y. 2025). On June 16, 2025, the federal District Court, Northern District of New York, issued a preliminary injunction enjoining enforcement of the amendments to PSL §65(13).

[165] Joint Proposal, pp. 2-13.

b. Executive Short Term Incentive Compensation

The Company proposed to recover a portion of its executive short-term incentive compensation as a component of a total executive compensation package, which a third-party consultant benchmarked against executive compensation levels at similarly situated companies.[166] Staff agreed that the Company's executive short-term incentive compensation plan focused on goals consistent with Commission policies, but recommended disallowing recovery of executive incentive compensation because the Company had not yet completed the recommendations from its most recent management and operations audit in Case 21-M-0541, which required the Company to implement necessary improvements to its executive incentive compensation program.[167] Although the Company maintained that the management audit recommendation regarding its executive incentive compensation program (Recommendation 2.7) would be fully implemented by February 2025, Staff pointed out the Company is required to meet with DPS Staff following implementation and that it was unclear whether Staff's process to verify proper implementation of the audit recommendations would be completed by the start of RY1.[168]

The Joint Proposal does not include funding for executive incentive compensation costs in RY1 but authorizes the Company to defer those costs, contingent upon Staff's acceptance of the Company's implementation of Recommendation 2.7 from the

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[166] Hearing Exhibit 173 (Company Workforce, Compensation and Benefits Panel Testimony), p. 34; Hearing Exhibit 187 (Confidential Company Exhibit WCBP-10); Hearing Exhibit 310 (Staff Accounting Panel Testimony), pp. 36-39.

[167] Hearing Exhibit 310 (Staff Accounting Panel Testimony), pp. 40-42.

[168] Hearing Exhibit 310, (Staff Accounting Panel Testimony), pp. 40-42; Hearing Exhibit 304 (Company Workforce, Compensation and Benefits Panel Rebuttal Testimony), pp. 10-12.

management and operations audit.[169] The revenue requirements do include executive incentive compensation for RY2 and RY3 in the amounts of $1.10 million and $1.14 million, respectively. However, if Staff has not accepted the Company's implementation of Recommendation 2.7 as completed by the end of each respective Rate Year, the Company will defer the rate allowance for future return to customers.

This deferral mechanism in the Joint Proposal properly recognizes the timing issue between the Company's purported implementation of Recommendation 2.7 and Staff's acceptance that the recommendation has been properly implemented, as well as the Company's interests in attracting and retaining qualified executives with an appropriate compensation package, including incentive compensation.[170] The inclusion of this deferral mechanism is reasonable because it ensures that ratepayers fund executive short-term incentive compensation only when Staff has concluded that the Company has properly implemented the previously identified necessary improvements to its executive compensation plan.

c. Gas Planning Proceeding – Gas Long-Term Plan

The Joint Proposal authorizes the Company to defer up to $665,000 in RY3 for preparation of its next gas long-term plan required to be filed in Case 20-G-0131,[171] which, among other things, requires gas utilities to file long-term gas plans

[169] Joint Proposal, p. 15.

[170] We also note that the executive compensation programs of various utilities, including the Company, are currently subject to a focused operation audit. Case 25-M-0043, Focused Operations Audit to Examine Management Incentive Compensation Programs at Electric, Gas, and Water Utilities, Order Initiating an Operations Audit (issued February 13, 2025).

[171] Joint Proposal, pp. 15-16.

approximately every three years.[172] Staff states that based on the filing of the Company's initial long-term plan and the Commission's Orders addressing other utilities' long-term plans, the parties to the Joint Proposal expect that the Company will be required to file its next long-term plan during or shortly after RY3.[173] However, because the timing remains uncertain, the costs for preparing the Company's next long-term gas plan are not included in revenue requirements but appropriately subject to the deferral mechanism mentioned above.

d. Non-Major Storm Expense

The Joint Proposal includes a downward-only deferral for non-major storm expense,[174] which, based on recent historical experience, is proposed to be increased by $7.5 million in RY1, $7.7 million in RY2, and $7.9 million in RY3.[175] The Company will reconcile actual non-major storm expense to the expense allowed in rates at the end of each Rate Year and record any net underspend as a deferral; the Company is not allowed to defer any overspending. Any cumulative underspending at the end of RY3 will be deferred for the benefit of customers. The Joint Proposal also includes a new quarterly reporting requirement for Non-Major Storm events and expenses, which will ensure transparency with respect to the Company's costs.[176] While no party in these proceedings proposed a Non-Major Storm deferral in their testimony, the inclusion of this provision in the Joint

[172] Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Adopting Gas System Planning Process (issued May 12, 2022), p. 10.

[173] Staff Statement in Support, p. 42.

[174] Joint Proposal, p. 17.

[175] Staff Statement in Support, p. 43.

[176] Joint Proposal, Appendix G; Hearing Exhibit 520 (Response to IR ALJ-14, Attachment 1).

Proposal is reasonable. Increases to the non-major storm expense will ensure necessary funding to the Company, while the deferral provision will protect ratepayers by requiring the Company to defer any underspending for the benefit of customers.

e. Permalock Tapping Tee Assemblies

The Joint Proposal permits the Company to defer the revenue requirement effect of incremental costs incurred to comply with inspection and/or remediation of PermaLock Tapping Tee Assemblies that are not otherwise addressed in generic proceedings.[177] Staff agreed in testimony to the Company's proposal for deferral authority to account for future inspection/remediation the Company performs with respect to Permalock Tapping Tees on its gas system.[178]

As the Commission recognized in Case 23-G-0083, the National Transportation Safety Board identified potential problems with the Permalock Tapping Tee, including improper installation regarding the locking sleeve and bolts, as well as degradation and fracturing of saddle bolts and O-rings that could lead to leaks or other incidents impacting public safety.[179] The Commission initiated a new proceeding in Case 23-G-0083 to provide a systematic and methodical means for gas utility companies to review, examine, and report on their use of tapping tees, as well as to potentially remediate tees that may have been improperly installed. We therefore find the Permalock

[177] Joint Proposal, pp. 17-18.

[178] Hearing Exhibit 104 (Company Gas Safety Panel Testimony), pp. 49-50; Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), pp. 69-72.

[179] Case 23-G-0083, Proceeding on Motion of the Commission Regarding an Examination by Gas Distribution Utilities Concerning the Installation of PermaLock Tapping Tee Assemblies, Order Initiating New Proceeding (issued March 16, 2023), pp. 1-2.

Tapping Tee deferral provision to be reasonable because it allows the Company to address known potential public safety concerns related to Permalock Tapping Tee Assemblies.

f. Property Taxes

The Joint Proposal reinstates the property tax deferral mechanism that was in place before the 2024 litigated rate case, which provides for future recovery from or pass back to customers of 90% of any difference between actual property tax expense and the rate allowances for each Rate Year.[180] Inclusion of the property tax deferral mechanism in the Joint Proposal is reasonable, given that it is a provision typically included in multi-year rate plans, was included in the Company's last multi-year rate plan, and is uncontested.[181]

g. Right of Way Maintenance - Distribution

The Joint Proposal continues the Company's current budget for the Right of Way Maintenance – Distribution account, setting the budget at $26.3 million for all three Rate Years, with a cumulative downward-only reconciliation.[182] This provides the Company with funding needed to cover distribution vegetation management activities and ensures that any underspending will be deferred for the benefit of customers.[183] In addition, the Joint Proposal implements a new quarterly reporting requirement concerning the Company's vegetation management and hazard tree removal program.[184] This reporting requirement will formalize information that has been provided informally to Staff and will

[180] Joint Proposal, p. 18.

[181] 2021 Rate Order, p. 18 and attached Joint Proposal, pp. 16-17.

[182] Joint Proposal, p. 19.

[183] Staff Statement in Support, pp. 44-45.

[184] Joint Proposal, p. 27.

enhance the transparency of the Company's programs and expenses.[185]

h. Solar on Company Facilities

Under the terms of the Joint Proposal, the Company will defer for the benefit of customers the revenue requirement effect of capital investments associated with installing solar on company facilities.[186] The Signatory Parties determined that the Company's proposed capital project to install solar PV panels on Company facilities would not proceed during the term of the Rate Plan.[187] Although the net plant targets in the Joint Proposal were adjusted to remove that project, the capital costs were included in the determining the revenue requirements.[188] To avoid the delay in filing the Joint Proposal that would "occur due to re-working time-consuming aspects of the rate design process," the Joint Proposal addresses the inclusion of those costs by providing a deferral mechanism to ensure that the funds are used for the benefit of ratepayers.[189]

i. Supplemental AMI Gas Study

The Joint Proposal authorizes the Company to defer costs up to $100,000 associated with a Supplemental AMI Gas Study.[190] The Company proposed the deferral to perform a supplemental study to evaluate the deployment of gas-only AMI endpoints and remote methane detectors in areas where it has

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185 Hearing Exhibit 520 (Response to IR ALJ-14, Attachment 1).

186 Joint Proposal, p. 19.

187 Staff Statement in Support, p. 45.

188 Joint Proposal, p. 9, Appendix C, Schedule 1 and Appendix E, Schedule 1. Specifically, the following amounts are included in the Common Other Capital Expenditures budgets: $0.174 million in 2025, $1.951 million in 2026, $0.642 million in 2027, and $0.183 million in 2028.

189 Hearing Exhibit 514 (Response to IR ALJ-10).

190 Joint Proposal, pp. 19-20.

only the gas franchise and another utility has the electric franchise, which occurs in limited southern portions of the Company's gas service territory.[191] Staff states that "remote methane detectors utilizing AMI endpoints would promote safety for customers and is worthy of studying."[192] We agree and find this deferral provision to be reasonable.

Rate Adjustment Mechanism

The Joint Proposal authorizes the Company to reinstate a Rate Adjustment Mechanism (RAM) to refund or recover the net balance of RAM electric and gas eligible deferrals and carrying charges, positive revenue adjustments (PRAs), and unencumbered negative revenue adjustments (NRAs).[193] RAM recoveries are limited to 2.5% of total electric or gas operating revenues as identified in revenue requirements in each Rate Year, and all RAM revenues and deferrals are subject to reconciliation. The RAM recovery dollar limitations and examples of the calculation of RAM surcharges or sur-credits are contained in Appendix H to the Joint Proposal, as are examples of bill impacts resulting from the RAM.

The Joint Proposal reinstates the RAM that existed prior to the 2024 Rate Order,[194] with minor modifications, including updated eligible deferrals and increased thresholds (from 2.4% to 2.5%) in relation to the revenue requirement. As Staff states, reinstituting the RAM in the context of a multi-year rate plan will reduce deferred regulatory asset and

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[191] Hearing Exhibit 104 (Company Gas Safety Panel Testimony), pp. 42-43; Staff Statement in Support, p. 45.

[192] Staff Statement in Support, pp. 45-46.

[193] Joint Proposal, p. 41.

[194] The Commission did not authorize continuation of the Company's then-existing RAM in the 2024 Rate Order.

liability balances that otherwise would need to be addressed in future rate proceedings.[195] The RAM reduces volatility of the Company's cash flows over a multi-year rate plan and can help avoid future rate impacts resulting from the creation of a large amount of deferred costs or credits.[196]

The RAM provision of the Joint Proposal is unopposed and reflects a reasonable compromise between the litigation positions of the Company and Staff by including maximum thresholds of 2.5% of total operating revenues, as requested by the Company, and excluding from the RAM-eligible items certain deferrals that Staff opposed in pre-filed testimony.[197]

Net Plant and Depreciation Targets and Reconciliation

The electric and gas net plant targets and depreciation expense targets are set forth in Appendix C, Schedule 1 to the Joint Proposal. The net plant targets are based on and reflect the agreed-upon total electric, gas, and common capital expenditures during the Rate Plan, which are contained in Appendix E to the Joint Proposal. The targets are the reasonable product of negotiation between the parties following Staff's extensive review of the Company's proposed

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[195] Staff Statement in Support, p. 76; Company Statement in Support, p. 38.

[196] Staff Statement in Support, p. 76; Company Statement in Support, p. 38.

[197] Hearing Exhibit 1 (Company Accounting and Tax Panel Testimony), p. 34; Hearing Exhibit 310 (Staff Accounting Panel Testimony), pp. 96-97.

capital programs and projects and depreciation expense.[198] The actual electric and gas net plant and depreciation expense at the end of each Rate Year will be calculated as described in Appendix C, Schedule 1 to the Joint Proposal. The average service lives, net salvage factors, and life tables used in calculating the theoretical depreciation reserve and in establishing depreciation expense are those the Commission determined in the 2024 Rate Order, which were undisputed in pre-filed testimony and are set forth in Appendix K to the Joint Proposal.

The Joint Proposal adopts Staff's recommendation to continue the current downward-only net plant reconciliation provision based upon the new net plant and depreciation expense targets.[199] Under the Joint Proposal, the actual electric and gas net plant and depreciation expense will be reconciled to the combined electric and gas net plant and depreciation targets for RY1 through RY3 on a cumulative basis at the end of RY3. If the cumulative revenue requirement impact from net plant and depreciation expense differences is negative at the end of RY3, the Company will defer the revenue requirement impact difference

[198] Compare Appendix C, Schedule 1, with Hearing Exhibit 387 (Staff Net Plant and Gas Infrastructure Panel Testimony) and Hearing Exhibit 393 (Staff Exhibit SNPGIP-3); Staff's Statement in Support, pp. 32-40; Hearing Exhibit 289 (Company Exhibit RRP-2R); Hearing Exhibits 313-314 (Staff Exhibits SAP-2 and SAP-3); Hearing Exhibit 189 (Company Accounting and Tax Panel Rebuttal Testimony) p. 6.

[199] Hearing Exhibit 387 (Staff Net Plant and Gas Infrastructure Panel Testimony), pp. 47-48; Hearing Exhibit 189 (Company Accounting and Tax Panel Rebuttal Testimony), p. 12.

for the benefit of customers.[200] If the cumulative revenue requirement impact is positive, no deferral will be recorded.

By calculating the deferral amount based on a three-year cumulative calculation, the Joint Proposal allows the Company to efficiently manage and operate its electric and gas businesses in response to unforeseen circumstances in any given Rate Year, while the downward-only mechanism protects customers from overcollection if the Company does not spend the capital budgets approved in these cases. This provision is reasonable and supports our finding that the Joint Proposal is in the public interest.

Performance Metrics

1. Electric Reliability

Consistent with the Company's and Staff's respective testimonial positions,[201] the Joint Proposal continues the Company's existing electric performance metrics of 1.30 for the System Average Interruption Frequency Index (SAIFI) and 2.50 hours for the Customer Average Interruption Duration Index

[200] The Company will apply carrying charges at the pre-tax rate of return to the amount deferred from the end of RY3 until the effective date of an order establishing the Company's next rate plan.

[201] Hearing Exhibit 47 (Company Electric Capital and Operations Panel Testimony), p. 63; Hearing Exhibit 340 (Staff Electric Resilience, Reliability, and Vegetation Management Panel Testimony), pp. 48-49.

(CAIDI).[202] Those metrics will apply to calendar years 2026, 2027, and 2028, and shall remain in effect thereafter until changed by the Commission.[203] The Company also will continue to be subject to NRAs of 30 basis points for each metric not met.

The Company and Staff disagreed in pre-filed testimony over the types of outages to be excluded from the SAIFI and CAIDI calculations. The Company initially proposed to apply exclusions that the Commission approved in the 2021 Rate Order, which excluded outages caused by major storms, catastrophic events beyond the Company's control, and incidents where problems beyond the Company's control involving generation or the bulk transmission system is the key factor in the outage.[204] In rebuttal testimony, the Company additionally requested to exclude outages resulting from Public Safety Power Shutoffs due to wildfire events.[205]

While Staff agreed in testimony with the exclusion for major storm outages, it disagreed with the remaining two proposed exclusions. Citing a 2004 Commission Order, Staff

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[202] The SAIFI measures the average number of times that a customer's service is interrupted during a year as calculated by dividing the total annual number of customers interrupted by the average number of customers served during the year. See Joint Proposal, Appendix S, Sheet 1 and n. 2. The CAIDI measures the average interruption duration time for customers that experience an interruption during the year to approximate the average length of time required to complete service restoration. The CAIDI is calculated by dividing the annual sum of all customer interruption durations by the sum of customers experiencing an interruption over a one-year period. Id., Sheet 1 and n. 1.

[203] Joint Proposal, pp. 41-42.

[204] 2021 Rate Order, p. 24 and Appendix Q to the attached Joint Proposal; Hearing Exhibit 47 (Company Electric Capital and Operations Panel Testimony), p. 69.

[205] Hearing Exhibit 228 (Company Electric Capital and Operations Panel Rebuttal Testimony), p. 40.

stated that a waiver process already exists under which the Company may petition the Commission on a case-by-case basis if it believes extraordinary circumstances other than a major storm exist that warrant excluding a specific outage from SAIFI and CAIDI reliability statistics.[206] In addition, noting that the SAIFI and CAIDI metrics are intended to gauge performance over the course of a year, Staff posited that the metrics allow the Company "time to make up a few days of poor performance over the course of year by the effective management of its workforce."[207] Although Staff did not have the opportunity to respond to the exception first raised by the Company in rebuttal testimony, Staff's arguments could apply equally to the requested exception for outages resulting from Public Safety Power Shutoffs due to wildfire events.

The Joint Proposal contains exceptions for outages caused by major storms, catastrophic events beyond the Company's control, and incidents where problems beyond the Company's control involving generation or the bulk transmission system are the key factor for the outage.[208] In addition, the Joint Proposal establishes a documented process for the Company to

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[206] Hearing Exhibit 340 (Staff Electric Resilience, Reliability, and Vegetation Management Panel Testimony), p. 50, citing Cases 02-E-1240 et al., Proceeding on Motion of the Commission to Examine Electric Service Standards and Methodologies, Order Adopting Changes to Standards on Reliability and Electric Service (issued October 12, 2004), p. 20 ("Listing more events, in addition to the 'major storm' exclusion, where data will be disregarded in evaluating reliability performance is unnecessary. Extraordinary circumstances can already be addressed through provisions for requesting a waiver under the [reliability performance] standards, and a more liberal listing of events that qualify as extraordinary would not improve the implementation of the waiver process").

[207] Hearing Exhibit 340 (Staff Electric Resilience, Reliability, and Vegetation Management Panel Testimony), pp. 50-51.

[208] Joint Proposal, Appendix S, Sheet 2.

follow for any potential exclusions other than outages from major storms. The process requires the Company to provide the Secretary and Director of the DPS Office of Resilience, Utility Security, Nuclear Affairs, and Emergency Preparedness with preliminary notice and supporting documentation of potential annual report outage exclusions. Additionally, the process provides that the Company may petition the Commission for exemption from the reliability performance metrics or NRAs, on a case-by-case basis.[209]

The electric reliability performance metrics are unopposed and continue the current SAIFI and CAIDI targets, which align with the Company's average performance over the last five years.[210] The associated NRAs are consistent with the NRAs applicable to other major electric utilities in New York State.[211] The outage exclusions are reasonable and mirror those in the Company's last three-year rate plan.[212] Finally, the SAIFI and CAIDI targets and associated NRAs will encourage the Company to continue to maintain system reliability to the benefit of ratepayers.

2. Gas Safety Metrics

The Joint Proposal provides that the Company's gas safety performance will be measured against performance metrics for emergency response time, leak backlog management, damage prevention, compliance with gas safety regulations, and LPP removal.[213] With the exception of the LPP removal metrics, for which existing targets will continue until the anticipated

[209] Id.

[210] Staff Statement in Support, p. 76.

[211] Id.

[212] 2021 Rate Order, attached Joint Proposal, Appendix Q.

[213] Joint Proposal, pp. 41-45 and Appendix T.

replacement of all LPP in calendar year 2028, the Joint Proposal requires the Company to satisfy more stringent gas safety performance targets than those currently in place. All metrics have associated NRAs for failure to meet targets, while only the emergency response, leak backlog management and damage prevention metrics have associated PRAs for exceeding targets.[214] The Company will also continue its leak-prone service replacement and community gas emergency response drill programs, both of which have associated PRAs, and its residential methane detector program, and pipeline safety management system.[215] The Joint Proposal exposes the Company to a risk of incurring total NRAs of 150 basis points[216] annually for failing to meet the agreed-upon performance standards and provides the opportunity to earn a maximum of 30 basis points in PRAs annually for exceeding metric target levels and excellent performance in its gas safety programs.[217] The Joint Proposal requires the Company to file with the Secretary an annual report on its gas safety performance as required by the Gas Safety Performance Measures report,[218] and provides that all metrics effective in calendar year 2028 will remain in effect until modified by the Commission.[219]

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[214] Id., Appendix T.

[215] Id., pp. 45-47, 54 and Appendix T.

[216] For the 12-month period ending on June 30, 2026, the value of a basis point is $128,866 for the Company’s electric operations and $51,801 for gas operations (Hearing Exhibit 394 (Staff Policy Panel Testimony), pp. 10-11; Hearing Exhibit 351 (Staff Finance Panel Testimony), p. 10).

[217] Joint Proposal, pp. 46-47 and Appendix T.

[218] Id., p. 42.

[219] Id., p. 47.

a. LPP Removal

Turning to the specific metrics set forth in the Joint Proposal, the Company will continue to be subject to NRAs of 15 basis points during calendar years 2025, 2026, and 2027 if it does not meet the annual LPP removal target of 15 miles.[220] In 2028, the Company will replace or eliminate its remaining current inventory of LPP – approximately seven miles – and will incur an NRA of two basis points per mile remaining as of December 31, 2028.[221] The Joint proposal requires the Company to seek alternatives to the replacement of pipelines scheduled to be eliminated, such as implementing Non-Pipes Alternatives (NPAs), but reserves to the Company the right to prioritize projects based on factors other than risk as it removes the last miles of LPP on its system.[222]

In testimony, the Company and Staff supported continuing the existing LPP removal target of 15 miles annually with an associated NRA of 15 basis points per year, as set forth in the Joint Proposal.[223] We conclude that the Joint Proposal reasonably continues the current target and associated NRAs,

[220] Id., p. 45.

[221] In a separate proceeding concerning the Company's long-term gas plan, the Company stated that its capital spending is projected to diminish significantly after its remaining LPP is completed in 2028 (Case 23-G-0676, Matter of a Review of the Long-Term Gas System Plans of Central Hudson Gas & Electric Corporation, Order Regarding Long-Term Natural Gas System Plan and Directing Further Actions (issued July 17, 2025), p. 61).

[222] Id. Other factors apart from risk that may be considered include, for example, the Company's ability to obtain required construction permits or efficiencies that may be derived from performing LPP projects that are closely located geographically but not physically connected (Staff Statement in Support, p. 83).

[223] Hearing Exhibit 104 (Company Gas Safety Panel Testimony), pp. 24-25; Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), pp. 27-30.

which fall within the range of metrics likely to have resulted from litigation. The LPP targets and associated NRAs will ensure continued public safety, minimize methane emissions, and further the State's goal of eliminating all LPP.

CLP opposes the LPP provisions of the Joint Proposal. CLP acknowledges that LPP has a tendency to leak and that it is in the public interest that leaking pipe be removed.[224] However, CLP nevertheless argues that the cost of replacing LPP that is not actually leaking – which it alleges, without proof, costs $4.3 million per mile to replace – is an unnecessary expense when the gas system should be downsized in order to permit a transition away from fossil fuel, as required under the CLCPA.[225] CLP argues that a strategic downsizing of the state's gas distribution system is necessary and opposes the replacement of LPP on the ground that it will lead to unmanageable stranded costs.[226]

With respect to NPAs, CLP states that the JP is essentially toothless because it contains no express goal, timeline or consequences for failure to meet given objectives.[227] Shrestha asserts that the cost of deploying NPAs is nearly even with replacing LPP and, thus, she urges the Commission to require the NPA program to be escalated when doing so is cost effective.[228]

We have previously rejected arguments like those advanced by CLP, and we do so again now, absent any articulated

[224] CLP Statement in Opposition, pp. 7-8.

[225] Id., p. 8.

[226] Id., pp. 7-8.

[227] Id., p. 11.

[228] Shrestha Statement in Opposition, p. 4.

rationale for departing from our prior precedent.[229] As we have explained, even functional LPP presents a risk in light of its increased potential for leaks and pipe failure, which may result in dangerous and hazardous conditions, including fires and explosions. Thus, we have concluded that public safety considerations prevent us from directing utilities to defer replacement of LPP in favor of addressing only identified leaks.[230] In addition to public safety benefits, the removal or replacement of LPP also furthers the goals of the CLCPA because it reduces actual and potential GHG emissions from the gas delivery system,[231] with most of the reductions in this case occurring in disadvantaged communities.[232]

Regarding NPAs, the Commission recently recognized the Company's successful pursuit of NPAs in lieu of LPP replacement.[233] The NPA provisions of the Joint Proposal will

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[229] Matter of Charles A. Field Delivery Serv., 66 N.Y.2d 516, 516-517, supra.

[230] Case 23-G-0627, supra, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plan with Minor Modifications, p. 65; Cases 23-G-0225 et al., KEDNY-KEDLI – Rates, Order Approving Terms of Joint Proposal and Establishing Rate Plans, with Minor Modifications and Corrections (issued August 15, 2024), pp. 89-90; Cases 22-E-0064 et al., ConEd – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans with Additional Requirements (issued July 20, 2023), p. 111.

[231] Case 23-G-0627, supra, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plan with Minor Modifications, p. 65; Cases 23-G-0225 et al., supra, Order Approving Terms of Joint Proposal and Establishing Rate Plans, with Minor Modifications and Corrections, pp. 90-91; 22-E-0064 et al., supra, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans with Additional Requirements, pp. 108-109.

[232] Company Statement in Support, p. 77.

[233] See Case 23-G-0676, supra, Order Regarding Long-Term Natural Gas System Plan and Directing Further Actions, p. 59.

build upon that success by requiring the Company to submit updated implementation plans for NPA programs related to Transmission Service Replacements and LPS Replacement, as well as implementation plans for each NPA associated with an Area of Pressure Concern Identified in System Modeling.[234] Further, the Company must provide outreach materials regarding its Clean Heat Program to customers with upcoming transmission service and LPS replacements and gas applicants within 100 feet of gas main. These provisions expand and improve upon the Company's NPA program. They are not toothless, as CLP argues; although the Joint Proposal does not contain deadlines, the recent Commission Order regarding the Company's long-term gas plan directed the Company to develop proposals for NPAs in one of its highly loaded segments and for two locations described in its final long-term plan, and to issue the request for proposals and file a copy of it with the Secretary within 120 days of that Order.[235] Moreover, the Joint Proposal does not simply require the Company to replace LPP, as Shrestha argues; rather, as noted above, the Joint Proposal obligates the Company to consider alternatives to replacement of pipelines scheduled to be eliminated, such as abandonment in favor of NPAs.[236] However, while the Company can provide outreach and seek to incentivize customers to voluntarily switch to electric service, it cannot legally force customers to terminate gas service by requiring LPP to be

[234] Joint Proposal, pp. 58-60.

[235] See Case 23-G-0676, supra, Order Regarding Long-Term Natural Gas System Plan and Directing Further Actions, pp. 79-80.

[236] Joint Proposal, p. 45.

replaced with NPAs whenever cost effective.[237] Accordingly, we reject CLP's and Shrestha's objections to the Joint Proposal's LPP provisions, and conclude that those provisions are in the public interest.

b. Leak Management

Under the Joint Proposal, the Company will be subject to NRAs of 15 basis points for each year in which the year-end total leak backlog (types 1, 2, 2A, and 3) exceeds 55 and NRAs of six basis points if the year-end total leak backlog is between 50 to 55 leaks.[238] The Company has the opportunity to earn PRAs as well: two basis points annually if the total leak backlog is between 15 to 29 leaks, four basis points annually if the total is between six and 14, and six basis points annually if the total is less than five.[239] The Joint Proposal states that the Company will be eligible to earn PRAs for leak management only if its repairable leak backlog (Types 1, 2 and 2A) at year end is six or less.[240] The targets and associated NRAs for this metric that are set forth in the Joint Proposal are more stringent than those in the Company's current rate plan, and both the PRAs and NRAs are more stringent than those proposed by the Company in its testimony.[241] Thus, this provision of the Joint Proposal, which is within the range of

[237] See PSL §30. CLP's challenge to the Joint Proposal's NPA provisions as toothless and its argument that the Commission should require a reduction of investment in LPP replacement (CLP Statement in Opposition, p. 11) similarly disregard the requirements of the PSL and the voluntary nature of NPA programs.

[238] Joint Proposal, pp. 42-43.

[239] Id., p. 43.

[240] Id.

[241] Hearing Exhibit 104 (Company Gas Safety Panel Testimony), pp. 17-19; Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), pp. 15-18.

potential litigated outcomes, will enhance public safety by incentivizing the Company to further reduce its year-end leak backlog. Moreover, the elimination of leaks from the Company's systems further supports the State's goal of reducing methane emissions.

c. Damage Prevention

Although the Company, in its initial testimony, proposed no changes to the current NRA targets for the damage prevention metric in the context of a multi-year rate case settlement,[242] the targets contained in the Joint Proposal are closer to Staff's more stringent recommended targets.[243] The Company's current targets and those set forth in the Joint Proposal combine all damage prevention categories in a single measure and result in NRAs of up to 20 basis points.[244] The targets, per 1,000 one-call tickets, are as follows:

Current Targets	**Joint Proposal Targets**	**NRA BPs**	**PRA BPs**
<1.65	<1.45	0	N/A
≥1.65 - <1.85	≥1.45 - <1.55	(5)	N/A
≥1.85 - <2.00	≥1.55 - <1.70	(10)	N/A
≥2.00	≥1.70	(20)	N/A

[242] Hearing Exhibit 104 (Company Gas Safety Panel Testimony), pp. 35-37.

[243] Joint Proposal, p. 44; Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), pp. 41-48.

[244] Staff asserts that the Company and Staff's Pipeline Safety Panel proposed that the Company be permitted to earn PRAs of up to 20 points for damage rates of 2.0 and 1.65, respectively (Staff Statement in Support, p. 81). That assertion is not supported by the record.

The Joint Proposal also permits the Company to earn annual PRAs of up to six basis points per year for damage prevention performance. Specifically, the Company is permitted to annually earn two basis points for successfully reducing its damage rates per 1,000 one-call tickets to 1.00 to less than 1.05, four basis points for reducing the rate to 0.95 to less than 1.00, and six basis points for reducing the rate to less than 0.95.[245]

This metric is designed to prevent the uncontrolled release of natural gas caused by excavation damage to natural gas pipes.[246] The far more stringent NRA targets for the overall damage rate and reinstated PRAs set forth in the Joint Proposal will, if achieved, lead to reduced pipeline damage, thereby increasing the safety of the Company's employees and the public.

d. Emergency Response Time

The proposed emergency response performance mechanism provides that the Company must respond to a minimum of 75% of calls reporting leaks or odors within 30 minutes, 90% within 45 minutes, and 95% within 60 minutes.[247] The mechanism includes NRAs of 12, eight and five basis points, respectively, for failure to achieve those targets.[248] These emergency response targets and NRAs remain unchanged from those currently in place, which were originally adopted prior to the 2024 Rate Order in

[245] Joint Proposal, p. 44.

[246] Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), pp. 36-42, 45-46; Hearing Exhibit 104 (Company Gas Safety Panel Testimony), p. 26.

[247] Joint Proposal, p. 42.

[248] Id., p. 42.

the Company's last three-year rate plan.[249] In addition, the Joint Proposal provides the Company with the opportunity to earn PRAs, up to a maximum of 6 basis points annually, for responding to 88% to 95% of calls within 30 minutes, higher targets than those currently in place.[250] The proposed targets and incentives promote public safety by incentivizing the Company to respond quickly to gas leak, odor and emergency reports, thereby minimizing the potential for safety-related incidents.

e. Gas Safety Violations Performance Measure

Finally, the gas regulations performance metric provides that the Company will incur up to a maximum of 75 NRAs for non-compliance with certain gas safety regulations, as identified by Staff field and records audits.[251] In each

[249] Compare Joint Proposal, p. 42 and Appendix T with 2021 Rate Order, attached Joint Proposal, p. 53 and Appendix R. Although Staff, in testimony, indicated that it was recommending a more stringent target for the emergency response time within 30 minutes and Staff's statement in support echoes that testimony (Hearing Exhibit 396 [Staff Pipeline Safety Panel Testimony], pp. 33-34; Staff Statement in Support, p. 78), the target proposed and that contained in the Joint Proposal are identical to those currently in place. Thus, as the Company asserts, the Company and Staff agreed on the minimum emergency response targets that would trigger NRAs. See Company Statement in Support, p. 41.

[250] Joint Proposal, p. 42; Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), pp. 32-35; Hearing Exhibit 105 (Company Exhibit GSP-1). In its Statement in Support, Staff acknowledges that it proposed, in testimony, that the Company earn a PRA of two, four and six basis points if it responded to between 88% and less than 92% of calls within 30 minutes, between 92% and less than 95% and 95% or more, respectively (pp. 78-79). Although the Joint Proposal adopts Staff's testimonial recommendation, Staff mistakenly recites in its Statement in Support that the Joint Proposal provides that the Company can earn PRAs of two, four or six basis points only if it responds to greater than 95%, 96% or 98% of emergency reports within 30 minutes, respectively.

[251] Joint Proposal, p. 44 and Appendix U, pp. 1-3.

calendar year from 2026 through 2028, the Company will be subject to an NRA of one-half basis point or one basis point for exceeding specified high-risk violation thresholds and one-quarter basis point for exceeding other-risk violation thresholds.[252] Should the number of occurrences of noncompliance with a regulation exceed 10, a remediation plan will be developed.[253] The Joint Proposal further identifies procedures for the Company to cure record deficiencies and dispute or appeal Staff's conclusions as to non-compliance.[254] The gas safety regulations performance metric contained in the Joint Proposal is more stringent than that in the current rate plan because it reduces the number of violations that will trigger the Company's exposure to NRAs as compared to the targets imposed under the 2024 Rate Order.[255] Therefore, this metric, as set forth in the Joint Proposal, provides the Company with a strong financial incentive to comply with the relevant pipeline safety regulations and improve the safety and reliability of the Company's gas system.

f. Additional Gas Programs

The Joint Proposal provides funding to continue or expand existing electric and gas programs, including the Company's LPS, Community Emergency Response Drill Program, Residential Methane Detector Program, and Pipeline Safety Management System.

The LPS program focuses on services that are considered to be LPP, such as wrought iron or bare steel, that are connected to a protected main but not included within the

[252] Id., Appendix U, p. 1.

[253] Id., p. 3.

[254] Id., pp. 2-3.

[255] Id., p. 1; Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), pp. 58-59.

LPP program itself.[256] The program is intended to proactively address services located in close proximity to a house before leaks cause a hazardous situation. In the 2024 Rate Order, the Commission agreed with the Company that the LPS program should be funded because it will lead to improvements in public safety and mitigate emissions of greenhouse gas.[257] However, because the program was new and its costs were unclear, the Commission concluded that the record before it at the time did not contain sufficient evidence to permit establishment of a PRA structure.[258] The Joint Proposal provides that, beginning in calendar year 2025, the Company is eligible to earn a PRA of four basis points if it removes 211 or more LPS per year, out of approximately 1,055 LPS remaining.[259] This target, which is substantially more stringent than that proposed by the Company in its testimony, was supported in Staff's testimony.[260] The target contained in the Joint Proposal is both reasonable and will further promote public safety by incentivizing the Company to remove all LPS within a five-year period.[261]

The Joint Proposal directs that the Company will continue its Community Emergency Response Drill Program, pursuant to which the Company conducts simulated full-scale gas emergency exercises in the community with first responder organizations in order to test and enhance communication

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[256] Joint Proposal, p. 45.

[257] 2024 Rate Order, p. 83.

[258] Id.

[259] Joint Proposal, p. 45; Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), p. 81.

[260] Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), pp. 82-84.

[261] Id., p. 84.

protocols and logistics of those organizations.[262] The exercises are designed to permit evaluation of the coordinated response of the Company and municipal agencies to gas events.[263] The Joint Proposal permits the Company to continue earning four basis points for each drill conducted, with a limit of two drills per year.[264] The Joint Proposal implements a new reporting requirement related to these drills. Specifically, the Company is to report the entities invited and schedule of events to the Secretary prior to commencement of each drill and, within 30 days of completion, a report that includes the attendance list, summary of activities, and cost of the event.[265] This program and the associated PRAs have been authorized by the Commission since 2021,[266] and it is funded through the Company's gas operations and maintenance (O&M) expenses.[267] Inasmuch the program has been well-received by local communities, enhances emergency preparedness, and was supported both by Staff and the Company in testimony,[268] its continued inclusion in the Joint Proposal is reasonable.

Finally, the Joint Proposal states that the Company will continue both its residential methane detector program and its pipeline safety management system (PSMS), which will be

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[262] Joint Proposal, p. 46.

[263] Id.

[264] Id.

[265] Id. The number of participants varies between 60 to 90. Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), p. 78.

[266] Hearing Exhibit 396 (Staff Pipeline Safety Panel Testimony), pp. 77-80.

[267] Joint Proposal, p. 54.

[268] Id.; Hearing Exhibit 104 (Company Gas Safety Panel Testimony), pp. 46-48.

funded though the Company’s gas O&M expenses.[269] The Company has distributed approximately 8,000 methane detectors to its customers and continues to replace defective units and respond to any alarms when the detectors are triggered.[270] In addition, the Company continues its progress in implementing the PSMS, the American Petroleum Institute’s recommended management tool used by pipeline operators to mitigate pipeline safety threats and risks, working toward a goal of zero safety accidents or incidents.[271] These provisions protect both the public and the Company’s employees, and their inclusion in the Joint Proposal is in the public interest.

Customer Service

The customer service provisions of the Joint Proposal, which are detailed below, are all unopposed, are acknowledged by the non-signatory parties PULP and CLP as demonstrating meaningful progress on a plan to improve the Company’s outreach to customers, offer protections for the most vulnerable customers, set forth a method for holding the Company financially accountable should it fail to supply adequate customer service, reflect compromise among the parties, and will provide significant benefits to the Company’s customers.

1. Customer Service Performance Indicators (CSPIs)

The terms of the Joint Proposal continue the CSPIs currently in place under the 2024 Rate Order; namely, PSC Complaint Rate per 100,000 Customers, Residential Customer Satisfaction, Percent of Calls Answered in 30 Seconds, and

[269] Joint Proposal, p. 54.

[270] Hearing Exhibit 104 (Company Gas Safety Panel Testimony), pp. 41-42.

[271] Id., pp. 43-45.

Appointments Kept.[272] Pursuant to the 2024 Rate Order, the Company is subject to maximum NRAs of 42 basis points for failure to meet the minimum performance targets for the enumerated CSPIs – five to 15 basis points if more than 1.0 to 1.2 complaints per 100,000 calls are "escalated" to DPS's Office of Consumer Services;[273] five to 15 basis points if the customer satisfaction survey index is below 89.0% to 85.3%;[274] and four to 12 basis point for failure to answer less than 67.0% to 55.8% of calls within 30 Seconds.[275] With regards to the Appointments Kept metric, the Company is required to credit customers $20 per missed appointment.[276] The Residential Service Terminations/Uncollectible Incentive Mechanism, which permits the Company to earn PRAs for reducing residential customer

[272] Joint Proposal, pp. 47-49 and Appendix V; 2024 Rate Order, p. 85; Cases 23-E-0418 et al., supra, Recommended Decision, pp. 322-323.

[273] Hearing Exhibit 334 (Staff Consumer Services Panel, Exhibit SCSP-2); Hearing Exhibit 330 (Staff Consumer Services Panel Testimony), pp. 21-24. Although the Company met its target for this metric during 2019-2021, its performance was 11.3 and 8.5 in 2022 and 2023, respectively.

[274] Hearing Exhibit 334 (Staff Consumer Services Panel, Exhibit SCSP-2); Hearing Exhibit 330 (Staff Consumer Services Panel Testimony), pp. 37-38. The Company missed the targets for this metric in 2021, 2022, and 2023. In contrast to its testimonial position, Staff erroneously states in its Statement in Support (p. 86) that the Customer Satisfaction Survey target is 87% instead of 89%.

[275] Hearing Exhibit 334 (Staff Consumer Services Panel, Exhibit SCSP-2); Hearing Exhibit 330 (Staff Consumer Services Panel Testimony), pp. 32-35. The Company missed the targets for this metric during each year from 2020 to 2023.

[276] Company Statement in Support, p. 52; Staff Statement in Support, p. 87.

service terminations and uncollectible expenses, remains paused.[277]

The Joint Proposal provides that these metrics will continue at the current target and NRA levels in calendar years 2026, 2027 and 2028, but the total basis points at risk for the percent of calls answered within 30 seconds will increase to 13 in 2027 and 15 in 2028.[278] Thereafter, CSPI targets and NRAs will remain in effect until modified by Commission order.[279] The Company expressly retains the right to petition for relief related to its inability to meet the CSPI targets due to events outside the Company’s control, such as natural disasters.[280] Although the Company proposed excluding complaints associated with commodity prices from the calculation of the PSC Complaint Rate metric, the Joint Proposal adopts Staff’s testimonial position that no complaint types be excluded from the calculation.[281] In addition, the Joint Proposal requires enhanced reporting associated with the percent of calls answered within 30 seconds, 30-60 seconds, one-five minutes, five-60 minutes, and more than one hour.[282]

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[277] Hearing Exhibit 330 (Staff Consumer Services Panel Testimony), p. 81.

[278] Joint Proposal, pp. 47-49. The Residential Service Terminations/Uncollectible Incentive Mechanism remains paused because post-pandemic residential service terminations commenced in May 2024 and, thus, there is insufficient historical data to support establishment of targets for this mechanism (Hearing Exhibit 330 (Staff Consumer Services Panel Testimony), p. 82-84; Staff Statement in Support, p. 88).

[279] Joint Proposal, p. 47.

[280] Id., p. 50.

[281] Company Statement in Support, p. 49; Staff Statement in Support, p. 86.

[282] Joint Proposal, Appendix M; Company Statement in Support, p. 51.

The CSPI provisions of the Joint Proposal contemplate reasonable earnings consequences based on the quality of services provided to customers and, thus, incentivize the Company to continue improving the customer experience. Moreover, the enhanced reporting requirements will increase transparency regarding the Company's customer service performance and efforts to address on-going concerns with that performance. Inasmuch as these provisions will lead to improved service to the Company's customers, we conclude that they are in the public interest.

2. Call Center Legislation Reporting

Chapter 107 of the Laws of 2025 amended PSL §65(13) to effectively require gas and electric corporations to have customer service calls answered within the utility's service territory and within the state, except under certain limited circumstances. As noted above, the Company is permitted to defer costs associated with the relocation of call center staff to its service territory because the cost of implementation of these requirements, which are the subject of federal litigation, is currently uncertain. The Joint Proposal also requires the Company to submit quarterly reports detailing its progress on call center staffing levels, hiring, training, and spending broken out by (1) labor, (2) external call center costs, (3) training, (4) equipment and (5) office space; any additional expenses outside the five enumerated categories must be accompanied by an explanation and justification.[283] This new reporting requirement is reasonable and in the public interest because it would provide transparency regarding the Company's efforts and the costs required to comply with the new call

[283] Joint Proposal, p. 50.

center mandates imposed by the Legislature, including what is likely to be a large-scale training and hiring effort.[284]

3. Language Access

The Joint Proposal includes provisions designed to expand language access for the Company's Limited English Proficient (LEP) customers. Among other things, the Joint Proposal requires the Company to provide customer bills and forms in Spanish, translate its website into Spanish, monitor and track LEP populations in its service territory on an annual basis, code all LEP accounts with customer's preferred languages in its Customer Information System, include in collections notifications a messaging block in the top five languages other than English and Spanish stating that the document is important and should be translated, and afford any customer that identifies as LEP a 15-day extension during which time the Company will not proceed with service termination.[285] The Company will also implement a plan to code as LEP any customer who self-identifies during the collection process and report to the Secretary on the program.[286] Because these provisions require stronger protections for LEP customers during the collections process and otherwise increase access to information for those customers, the provisions are lauded by PULP, which proposed many of them, and CLP.[287] We agree that the language access provisions are reasonable and in the public interest because they will enhance the customer service provided to LEP customers and ensure that those customers are provided

[284] Staff Statement in Support, p. 88.

[285] Joint Proposal, p. 51.

[286] Id., pp. 51-52.

[287] PULP Statement in Neutrality, p. 7; CLP Statement in Opposition, p. 4; Company Statement in Support, pp. 53-54.

sufficient language assistance throughout the collections process.

4. Short-Term Payment Agreements

This provision of the Joint Proposal, which requires the Company to implement a plan by the end of RY2 to waive finance charges for customers with short-term payment agreements, addresses PULP's concerns that the Company continues to assess late payment fees on customers entering into such payment agreements.[288] The Company's short-term payments are distinct from the deferred payment agreements required under the Home Energy Fair Practices Act (HEFPA).[289] This provision is reasonable and in the public interest because it extends similar protections afforded by HEFPA to customers choosing to use a short-term payment agreement to settle their arrears.

5. Voluntary Protections During Extreme Weather

The extreme weather provisions of the Joint Proposal ensure that customers will continue to receive electric and gas service during extreme weather conditions. The Company agrees to refrain from scheduling residential terminations on days that are predicted to be below freezing or in which the "feels like" temperature is predicted to be at or below 32 degrees for two consecutive days, and on days for which the heat index is forecasted to be, or actually is, 93 degrees or higher.[290] Additional protections include continuing service during the cold weather period – November 1 through April 15 – if the Company has accepted a Home Energy Assistance Program (HEAP) payment during that period, acceptance of any HEAP payment as

[288] Joint Proposal, p. 52; PULP Statement in Neutrality, pp. 4-5; Staff Statement in Support, pp. 89-90; Company Statement in Support, p. 55.

[289] PSL §37.

[290] Joint Proposal, p. 53.

entitling the customer to a deferred payment agreement regardless of any previous defaults, and a moratorium on winter terminations for all customers who are elderly, blind, or disabled.[291] These provisions will be continued unless the Commission establishes more stringent protections in Case 24-M-0586.[292] This provision of the Joint Proposal is reasonable because it provides protections to the most vulnerable customers during the times of year in which extreme weather poses the greatest health and safety risk.

6. Outreach and Education

The Joint Proposal requires the Company to continue to file an Outreach and Education Plan with the Secretary by April 1 of each Rate Year.[293] The Company is required to use the template in Appendix W, which highlights major areas of interest to the Company’s customers and the improvements the Company may undertake during the following year, using related achievements from the prior year as benchmarks.[294] This requirement is in the public interest because it promotes transparency and provides all stakeholders with detailed information regarding the Company’s anticipated communications and customer engagement activities, and it ensures that outreach and education programs remain available to the Company’s customers.

Low-Income Affordability Programs

The Joint Proposal continues the Company’s EAP, which provides eligible customers with bill discounts and waiver of reconnection fees.[295] The Joint Proposal provides for EAP rate

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[291] Id., pp. 52-53.

[292] Id., p. 52.

[293] Id., p. 54.

[294] Staff Statement in Support, p. 91.

[295] Joint Proposal, p. 31.

allowances of $11.0 million for electric and $3.4 million for gas in all three Rate Years, subject to symmetrical deferral.[296] The Company will allocate any overcollection of EAP funds as of June 30, 2025, to augment approved rate allowances in support of program costs. If the program costs exceed both the rate allowances and the current over-collection balances during the term of the Rate Plan, the Company will record any additional incremental funding as a deferral for later collection.[297] As noted above, for Tier 1 EAP participants, bill discounts will reduce total monthly electric bills by an average of 4.2% and lead to an increase in average monthly gas bills of only about 1.0%.[298] These provisions will mitigate the rate increases in the Joint Proposal for EAP participants, ensure that the Company is in compliance with the Commission's Energy Affordability Policy set forth in Case 14-M-0565,[299] and allow the Company to reconcile any over- or under-expenditures if participation varies from the data used to calculate these rate allowances. At PULP's suggestion,[300] the Company will also begin tracking and recording monthly EAP self-enrollments and include the information in its reporting in Case 14-M-0565.[301] The Company will perform an internal audit of EAP enrollment records and participant eligibility from September 2021 through December 2024, including the processes and frequency of the Company's automated file matching with the New York State Office of

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[296] Id.

[297] Id.

[298] Id., Appendix Q, pp. 1, 15.

[299] Case 14-M-0565, supra, Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings.

[300] Hearing Exhibit 444 (Testimony of William D. Yates), pp. 12, 34.

[301] Joint Proposal, p. 34.

Temporary and Disability Assistance.[302] The new monthly reporting requirement, the internal audit, and the reports filed with the Secretary in connection with the audit will ensure the accuracy of EAP enrollment and reporting, as well as help to assess the effectiveness of the Company's outreach efforts to identify and encourage enrollment in the EAP.

In that regard, the Joint Proposal provides that the Company will take enhanced outreach actions aimed at increasing enrollment in its EAP, including analyzing non-EAP account histories for indicators of past or current financial need, such as prior participation in the EAP or past receipt of HEAP grants. The Company will initially focus on zip codes in which the percentage of total residential customers enrolled in the EAP is less than the service territory's overall participation rate of 4.6%.[303] These provisions are also responsive to recommendations made by PULP regarding the Company's EAP enrollment.[304] The Joint Proposal directs the Company to endeavor to achieve enrollment of 15,500 EAP participants during RY1; in RY2 and RY3, the Company will waive any current-month late fees for any customers that self-enroll in the EAP if enrollment falls below 15,500.[305]

We conclude that the EAP provisions in the Joint Proposal are in the public interest and consistent with the Commission's EAP Orders and policies. The terms of the Joint Proposal will ensure that low-income participants receive a discount to provide financial relief from their energy bills,

[302] Id., p. 33.

[303] Joint Proposal, p. 32.

[304] Hearing Exhibit 444 (Testimony of William D. Yates), p. 34.

[305] Joint Proposal, pp. 32-33. As noted above, the Company had 13,598 participants in its EAP as of April 30, 2025 (Hearing Exhibit 526 (Response to IR ALJ-20)).

within the framework previously established by the Commission in Case 14-M-0565. Moreover, the audit and reporting requirements will provide transparency regarding the Company's EAP processes and allow stakeholders to assess the success of the Company's EAP enrollment efforts. We note that, although neither party supports the Joint Proposal, both PULP and CLP praise the EAP provisions on the ground that they will positively impact the service territory's most vulnerable population.[306] The EAP provisions thus reflect a reasonable compromise and fair accommodation among normally adversarial parties.

Earnings Adjustment Mechanisms (EAMs)

As proposed by the Company, the Joint Proposal sets forth five EAMs: (1) distributed energy resource (DER) PV utilization (based on the sum of the MW alternating current (AC) nameplate of incremental third-party solar installations of five MW or less); (2) storage DER utilization MW (based on the sum of the MW AC nameplate of all battery energy storage system interconnections of five MW or less, excluding company-owned storage); (3) new electric load management (based on the operationally available MWs achieved through both the Company's load management programs and the portion of the NYISO Special Case Resource located within the Company's service territory in a given calendar year); (4) new residential managed charging (based on avoided charging of EVs during peak hours and decreased peak coincident demand of customers enrolled in ChargeSmart); and (5) EV adoption (based on incremental tons of lifetime CO2 reduced as a result of incremental EV registrations in the Company's service territory).[307] In addition, as

[306] PULP Statement in Neutrality, pp. 4-6; CLP Statement in Opposition, pp. 3-4.

[307] Joint Proposal, p. 54 and Appendix X, pp. 1-12, 16-17.

recommended by both the Company and Staff, the Joint Proposal continues the Company's four scorecard metrics, which are used for tracking purposes only and include three electric operations metrics (load factor, residential energy intensity, and commercial energy intensity) and one gas operations metric (gas peak reduction).[308] The Company is required to file an annual report on both the EAMs and scorecard metrics, with reports due by June 1 of the following year.[309] Incentives will continue to be recovered through the Miscellaneous Charges EAM factor, which is a component of the Company's Energy Cost Adjustment Mechanism.[310]

The corresponding dollar values for the EAMs established in the Joint Proposal, as well as the details about each EAM measurement, achievement standard, and target level, are set forth in Appendix X to the Joint Proposal. In its initial testimony, the Company proposed that the total annual maximum financial incentive should be 55 basis points across the five EAM categories, while Staff recommended that the Company be provided with the opportunity to earn an annual maximum of 20 basis points.[311] The Joint Proposal provides that if the Company attained the highest metric levels for all five EAMs, it would earn approximately $4.59 million in 2026, approximately $4.85 million in 2027, and approximately $4.96 million in 2028 –

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[308] Joint Proposal, pp. 54-55 and Appendix X, pp. 12-16; Hearing Exhibit 38 (Company Earnings Adjustment Mechanisms Panel Testimony), p. 23; Hearing Exhibit 344 (Staff Energy Sustainability and Earnings Adjustment Mechanism Panel Testimony), p. 65.

[309] Joint Proposal, Appendix X, p. 17.

[310] Id., p. 55.

[311] Hearing Exhibit 38 (Company Earnings Adjustment Mechanisms Panel Testimony), p. 12; Hearing Exhibit 344 (Staff Energy Sustainability and Earnings Adjustment Mechanism Panel Testimony), pp. 69-71.

equivalent to 34 basis points in each calendar year.[312] The targets and incentive levels for each metric therefore reflect a reasonable compromise between the litigation positions of Staff and the Company.[313]

EAMs are not related to traditional basic service. Instead, they are incentive measures designed to promote new performance expectations that may run counter to both conventional methods of operation and a utility's implicit financial incentives embedded in the cost-of-service ratemaking model.[314] Staff and the Company argue that the EAMs set forth in the Joint Proposal are in the public interest, asserting that they support the goals of the CLCPA by promoting increased interconnection of DERs, will assist the Company in avoiding investments in infrastructure that would otherwise be needed to meet demand by managing load on its system as electric demand grows, and incentivize the Company to actively support EV adoption in its service territory while encouraging enrollment in and the performance of the ChargeSmart program to more efficiently incorporate EVs and charging infrastructure into the Company's system.[315]

No parties oppose the EAMs set forth in the Joint Proposal, but MI expresses only qualified support for them. MI acknowledges that "[i]nasmuch as customers are required by current Commission policy to fund EAMs – in addition to utility electric and gas revenue requirements and a growing assortment

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312 Joint Proposal, Appendix X, p. 1.

313 Company Statement in Support, pp. 59-63.

314 Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), p. 59.

315 Staff Statement in Support, p. 94; Company Statement in Support, pp. 60-63.

of costly State and Commission policy initiatives – there was little question that EAMs of some type would be included as part of any multi-year rate plan negotiated herein."[316] However, MI indicates that, despite its reservations about the Commission's current policies, the EAMs set forth in the Joint Proposal should be adopted because their total potential value is closer to the position proposed by Staff and, thus, the Joint Proposal reduces customers' exposure to these shareholder incentives in comparison with the EAM portfolio proposed by the Company.[317] The EAMs in the Joint Proposal are the product of negotiation, within the range of outcomes in pre-filed testimony and aligned with the State's energy goals. In addition, the proposed EAMs will promote grid reliability by supporting programs that will integrate clean energy technologies from emerging markets, optimize participant performance in electric demand response programs, and decrease peak coincident EV charging demand. The proposed EAMs appropriately balance the interests of the ratepayers and the Company's shareholders, as well as supporting the public policy of the State. Thus, the EAM provisions are reasonable and support our conclusion that the Joint Proposal is in the public interest.

Tariff-Related Matters

Section XII of the Joint Proposal sets forth various tariff-related matters.[318] Revenue decoupling mechanisms (RDMs) and reconnection charges are discussed below.

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[316] MI Statement in Support, p. 19.

[317] Id., pp. 19-20.

[318] Joint Proposal, pp. 34-38.

1. Revenue Decoupling Mechanisms

The Commission first required utilities to propose RDMs in a 2007 Order.[319] RDMs are designed to eliminate or substantially reduce the link between sales and utility revenues to encourage utilities to aggressively pursue energy efficiency measures, which, by definition, would otherwise result in decreased sales volumes.

The Joint Proposal continues the Company's electric and gas RDMs adopted in the 2024 Rate Order.[320] Neither the Company nor Staff proposed any changes. Both the electric and gas RDMs are revenue-per-class models that apply to certain service classifications identified in the Joint Proposal and relevant appendices. Actual delivery revenues by service class or subclass for RDM-eligible classes are compared monthly to delivery revenue targets. If the monthly actual delivery revenue exceeds or falls short of the applicable delivery revenue target, the excess or shortfall is accrued for refund to or recovery from customers at the end of the semi-annual electric RDM period and the annual gas RDM period. Electric and gas bill credits will be included in the reconciliation of target and actual revenue under the respective RDM. RDM targets are set forth in Appendix S to the Joint Proposal. The RDM mechanisms, which are unopposed by any party, are reasonable.

2. Reconnection Charges

The Company charges a reconnection fee for restoring power to customers whose service has been discontinued for

[319] Cases 03-E-0640 et al., Investigation of Potential Electric and Gas Delivery Rate Disincentives Against Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation, Order Requiring Proposals for Revenue Decoupling Mechanisms (issued April 20, 2007).

[320] Joint Proposal, pp. 34-35.

nonpayment.[321] The reconnection charge reflects labor costs for collectors, commercial representatives, line crews, gas crews, call center and dispatch labor costs, as well as vehicle and material costs related to travel and performing reconnection.[322] The current reconnection charges, which have not been updated since July 2018,[323] are $60 for normal business hours, $220 for normal business hours with a gas mechanic crew, $120 for other than normal business hours, and $310 for other hours with a gas mechanic crew.[324] Under the Joint Proposal, the new rates will be $70 for normal business hours, $260 for normal business hours with a gas mechanic crew, $130 for other hours, and $350 for other hours with a gas mechanic crew.[325] The Company had proposed those increases to reflect the rising costs associated with service reconnections, and Staff agreed with those updated fees as reasonable and consistent with cost-causation principles.[326]

Although no party objected in pre-filed testimony to the proposed changes to the reconnection fees, in opposing the Joint Proposal CLP now states that the likelihood of growing arrears and the number of customers subject to termination of service make the increased fees seem "overly harsh and indeed

[321] Company Statement in Support, p. 31; Staff Statement in Support, p. 69.

[322] Hearing Exhibit 79 (Company Forecasting and Rates Panel Testimony), p. 61.

[323] Cases 17-E-0459 et al., Central Hudson – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued June 14, 2018), p. 19; Staff Statement in Support, p. 69.

[324] Staff Statement in Support, p. 69.

[325] Joint Proposal, p. 36.

[326] Hearing Exhibit 79 (Company Forecasting and Rates Panel Testimony) p. 61; Hearing Exhibit 401 (Staff Rates Panel Testimony), p. 50.

punitive."[327] The Company responds that the reconnection charges reflect the current actual costs to reconnect customers and that the Joint Proposal continues the waiver of reconnection fees as a component of the EAP.[328]

Based on the record, we agree that the increases to the reconnection charges appropriately follow cost-causation principles and reasonably reflect rising costs and, therefore, we reject CLP's argument. In doing so, we emphasize that EAP program participants remain eligible for a waiver of the reconnection fee that would otherwise apply.

Economic Development Programs

The Joint Proposal contains funding of $193,000 in RY1, $400,000 in RY2, and $400,000 in RY3 for four electric economic development grant programs - three existing and one new.[329] The existing programs are the Manufacturing Building and Infrastructure Program, Manufacturing Productivity Program, and Expansion and Retention for Manufacturers Program. The newly proposed program is the Workforce Clean Energy Program. The programs would be subject to the now-existing two-way true-up mechanism for economic development expenses.[330] The Commission discontinued the Company's gas economic development programs in the Company's last Rate Plan.

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[327] CLP Statement in Opposition, p. 7.

[328] Company Reply Statement in Support, p. 12, citing Case 14-M-0565, supra, Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings; Company Statement in Support, p. 26.

[329] Joint Proposal, Appendix A, Schedule 1.

[330] Hearing Exhibit 149 (Company Revenue Requirements Panel Testimony), p. 33.

1. Existing Economic Development Programs

The Infrastructure for Manufacturers Program provides grants of up to $200,000 to help "accelerate the growth of manufacturing capability by targeting former manufacturing buildings and undeveloped sites" in the Company's service territory.[331] The Manufacturing Productivity Program provides grants up to $15,000 to support manufacturers' efforts "to incorporate and employ sustainable, scalable processes to optimize and improve their operational capacity."[332] The Extension and Retention for Manufacturers Program provides grants of up to $200,000 to support manufacturers who are making a new capital investment within the Company's service territory. The Company states that these existing economic development programs "are targeted at creating or retaining jobs, facilitating additional capital investments and fostering economic growth or, at a minimum, promoting economic stabilization with the Central Hudson service territory."[333] The Company asserts that those programs also align with the State's FAST NY Shovel-Ready Grant Program, which provides grants to prepare and develop sites statewide to jumpstart New York's shovel-readiness to attract large employers.[334]

Continuation of the Company's existing programs is unopposed. The existing Economic Development programs appropriately "encourage the relocation, growth, expansion and retention of business customers in the [Company's] service

[331] Hearing Exhibit 34 (Company Customer Experience Panel Testimony), p. 24.

[332] Id.

[333] Id., p. 25.

[334] Id., p. 25-26.

territory,"[335] and we agree with Staff's assessment that the funding for the programs is reasonable.

2. New Workforce Clean Energy Program

The new Workforce Clean Energy Program will provide grants of up to $200,000 to educational institutions focused on developing a skilled workforce to meet the demands of the clean energy sector.[336] The Company will explore partnerships with local community colleges, vocational schools, non-profit organizations, and industry associations developing and implementing training and micro-credential programs that align with industry needs. Among various other criteria used to determine the grant amount to be awarded to particular recipients, the Company will consider the "potential impact on the local workforce, including the number of individuals expected to be trained and the anticipated job creation within the Company's service territory"; the "extent to which the institution has established partnerships with local industries, community organizations, or other educational institutions to enhance the training program"; and the "availability of supplemental or matching funds from other economic development agencies or partners."[337]

In addition, under the Joint Proposal, the Company will include a separate chapter in its annual Economic Development Report discussing the Workforce Clean Energy Program and providing the following information for any grant awarded through that program: (1) the education/training program funded;

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[335] Cases 05-E-0934 et al., Central Hudson – Rates, Order Establishing Economic Development Plan Procedures (issued August 24, 2009), p. 1; Case 00-E-1273, Central Hudson – Electric Rates, Order Adopting Economic Development Program (issued October 3, 2002), pp. 1, 9.

[336] Joint Proposal, p. 38.

[337] Id., p. 39.

(2) how the Company determined the individual grant award amount; (3) the intended result of the awarded grant; (4) the number of participants in the education/training program; (5) the method of tracking participant outcomes to demonstrate whether participants secure employment in the Company's service territory; (6) the additional economic development assistance the applicant has applied for and received, or will receive in addition to a Workforce Clean Energy Program grant; and (7) any feedback received from participants and the facility that hosted the education/training program.[338]

In testimony, Staff supported the Workforce Development Program with enhanced reporting requirements,[339] the vast majority of which are reflected in the Joint Proposal, as discussed above. We agree with Staff's assessment that the enhanced reporting requirements in the Joint Proposal will allow Staff and other interested stakeholders to monitor the progress and success of the newly created program.[340] Moreover, we conclude that the enhanced reporting requirements, as well as the criteria the Company will use in determining grant award amounts, the institutional partnerships that the Company will seek to form, and the Company's experience in administering economic grant programs, properly address the concerns CLP raised in pre-filed testimony about the Company's inexperience with clean energy workforce development grants.[341] We also note that CLP did not raise such concerns again in opposition to the Joint Proposal.

[338] Id., pp. 39-40.

[339] Hearing Exhibit 330 (Staff Consumer Services Panel Testimony), pp. 95-97.

[340] Staff Statement in Support, p. 73.

[341] Hearing Exhibit 440 (Corrected Direct Testimony of Jessica Mullen), pp. 16-25.

We conclude that the Workforce Clean Energy Program will help develop a skilled workforce in the clean energy sector, a critical need to address the State's changing energy landscape. The new program will be available to help ratepayers in the Company's service territory, including those in disadvantaged communities, to obtain jobs essential to the growing clean energy market in New York State."[342] Accordingly, we find the Workforce Clean Energy Program set forth in the Joint Proposal to be reasonable and in the public interest.

3. Economic Development Program Reporting

Under the Joint Proposal, the Company will continue to file an annual Economic Development Report by April 1 of each year that details economic development activity for the prior calendar year and is consistent with Commission requirements established in Case 05-E-0934.[343] As stated above, the annual report also will include enhanced reporting requirements for the new Workforce Clean Energy Program. The new reporting requirements, which are unopposed, are the reasonable product of negotiation and fall within the range of likely litigated outcomes.

Moreover, in response to Staff's recommendation in pre-filed testimony that the Company develop criteria that would provide priority treatment to projects located in disadvantaged communities, the Company agreed that it would proceed with an expedited review and approval of applications for funding for projects located within disadvantaged communities.[344]

[342] Hearing Exhibit 34 (Company Customer Experience Panel Testimony), pp. 26-27.

[343] Cases 05-E-0934 et al., supra, Order Establishing Economic Development Plan Procedures.

[344] Hearing Exhibit 330 (Staff Consumer Services Panel Testimony), pp. 98-99; Hearing Exhibit 210 (Company Customer Experience Panel Rebuttal Testimony), p. 30.

CLCPA

CLP generally describes the Joint Proposal as being an "[i]nadequate [r]esponse" to the CLCPA and, specifically, takes issue with the proposed continuation of the Company's differentiated gas[345] pilot program, which CLP classifies as a "false 'solution[].'"[346] CLP maintains that renewable natural gas programs have limited or questionable value due to a lack of credible regulation and independent certification authorities. CLP further takes issue with the fact that the Company's pilot program lacks sufficient detail as to what type of differentiated gas the Company will procure.[347] According to CLP, the differentiated gas pilot program improperly incentivizes ongoing, costly investment in the Company's gas infrastructure, creating the risk that fewer customers will be asked to cover increasing costs as more customers convert fully to electric utility service.[348]

In response to CLP's concerns, Staff notes that the Joint Proposal requires the Company to purchase differentiated gas that "meet[s] the highest available certification standards" and continues to limit the Company's purchases to an annual cost above traditional gas supplies of $200,000 – a figure Staff deems to be "very small" compared to the Company's total gas

[345] "Differentiated gas", "responsibly sourced gas", and "renewable natural gas" are terms that generally refer to the same product.

[346] See generally CLP Statement in Opposition, pp. 7-11. CLP acknowledges that most of its arguments previously were submitted in other cases, notably in the Company's long-term gas system planning case (Case 23-G-0676) and the Company's last rate case. Its opposition to the provisions in the Joint Proposal regarding the Company's LPP program is discussed above in the Performance Metrics section of this Order.

[347] CLP Statement in Opposition, p. 8.

[348] Id.

purchases.[349] For its part, the Company responds that, regardless of CLP's claims, the differentiated gas pilot program "will result in GHG emissions reductions of approximately one million pounds between 2025 and 2028."[350]

The 2024 Rate Order permitted the Company to implement a pilot program to procure differentiated gas up to a cost of traditional gas supply of $200,000 during the rate year.[351] In its initial testimony, Staff agreed with the Company's proposal to continue the pilot program but recommended that the differentiated gas purchases satisfy "the highest certification standards available" and that the Company include additional information in its monthly differentiated gas report.[352] The Joint Proposal incorporates Staff's recommended enhancements to the pilot program.

Contrary to the arguments set forth by CLP, the provision allowing for the pilot program to continue is reasonable, consistent with the CLCPA, and in the public interest. As we previously have recognized, and as discussed above, "[i]t is inarguable that the State's gas transmission and distribution systems are in a transitional period."[353] However, utilities remain legally obligated to continue to provide safe and reliable gas service to those customers who request it.[354]

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[349] Staff Reply Statement in Support, p. 18.

[350] Company Reply Statement in Support, p. 22.

[351] 2024 Rate Order, p. 64.

[352] Hearing Exhibit 384 (Staff Gas System Planning and Reliability Panel Testimony), pp. 29-30.

[353] Case 23-G-0627, supra, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plan with Minor Modifications, p. 95.

[354] See PSL §30; see also New York State Climate Action Council, Scoping Plan (December 2022), p. 351 (recognizing the continued need to maintain existing gas infrastructure).

During this transition period, pilot programs such as the one proposed in the Joint Proposal provide an opportunity for utilities to satisfy their legal obligations to provide safe and reliable service while also incrementally reducing GHG emissions. As we recently acknowledged, additional analyses regarding the long-term feasibility, environmental impact, and cost-effectiveness of RNG and differentiated gas should be conducted as more data becomes available to ascertain the costs and benefits of these programs in the future.[355] However, for now, the use of differentiated gas has the potential to reduce GHG emissions and, therefore, we are not persuaded that the pilot program should be discontinued at this time.[356]

Further, the Joint Proposal appropriately adds limitations on the Company's differentiated gas pilot program to ensure that the program remains narrow in scope and is tailored to protect customers from excessive and wasteful costs as this nascent industry is developed and, further, is consistent with similar pilot programs authorized for other utilities.[357]

While CLP may be generally dissatisfied with the pace at which the Company is taking action to decrease reliance on its natural gas infrastructure, CLP's arguments ignore the Company's obligations under the PSL to serve customers. As the Commission has recently - and repeatedly – explained, "application of the CLCPA cannot be done in a vacuum but,

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[355] See Case 23-G-0676, supra, Order Regarding Long-Term Natural Gas System Plan and Directing Further Actions, pp. 45-47.

[356] See Matter of Charles A. Field Delivery Servs., 66 N.Y.2d at 516-517, supra.

[357] See, e.g. Case 23-G-0627, supra, pp. 91-95; Cases 22-E-0317 et al., supra, Order Adopting Joint Proposal, Joint Proposal, pp. 70-71; Cases 22-E-0064 et al., supra, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans with Additional Requirements, p. 45.

rather, must be balanced against and consistent with the" PSL's mandates to provide safe and reliable gas service to those customers who demand it – the Company "simply cannot legally refuse gas utility customer service requests."[358]

The CLCPA does not require a reduction of utility gas system infrastructure. Instead, it requires only that agencies consider whether their decisions "are inconsistent with or will interfere with the attainment of statewide greenhouse gas emissions limits" established in ECL Article 75.[359] The instant Joint Proposal contains projects and programs directly related to managing and reducing emissions that contribute to the attainment of the State's policy goals[360] and, therefore, approval of this Joint Proposal would not be inconsistent with the CLCPA.

Finally, we are satisfied that the terms of the Joint Proposal will not disproportionately burden disadvantaged communities.[361] The Joint Proposal contains low-income protections, which generally benefit disadvantaged communities, and proposes various capital projects located in disadvantaged communities that are intended to improve the safety and reliability of gas and electric service in those communities. While these projects may have minor, short-term impacts, such as

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[358] Cases 23-E-0317 et al., supra, Order Adopting Joint Proposal, pp. 55-56.

[359] CLCPA §7(2).

[360] These provisions include those specifically identified in the Climate and Energy Leadership Initiatives section of the Joint Proposal, many of which are discussed above, such as the LPP program, the elimination of gas declining block rates, and the continuation of the Company's efforts to identify NPAs. See also Attachment A to Staff Statement in Support for projected emissions impacts over the term of the proposed rate plan.

[361] No party argues the contrary; rather, this is an assessment that is required to be made by CLPCA §7(3).

construction-related disruptions, the long-term benefit to the communities in which the projects will be constructed outweigh the short-term inconveniences.[362]

Management Audit

Both Staff and the Company provided testimony concerning PSL §66(19)(c), which requires the Commission, upon the application of a gas or electric corporation for a major change in rates, to review the utility's compliance with Commission directions and recommendations made in the most recently completed management and operations audit.[363]

In Case 21-M-0541, the Commission initiated a comprehensive management and operations audit of the Company. In April 2023, the Commission authorized the public release of Overland Consulting's final audit report, which contained 37 recommendations for improvement.[364] The Commission ultimately approved the Company's final implementation plan, with modifications, in March 2024.[365] As of its June 2025 implementation plan update, the Company indicates that it has completed 32 recommendations and expects to implement the remaining five recommendations by July 2026.[366]

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[362] See Hearing Exhibit 17 (Company Climate Leadership and Sustainability Panel Testimony), pp. 12-14; Hearing Exhibit 19 (Company Exhibit CLSP-2); Hearing Exhibit 325 (Staff Climate Leadership and Community Protection Act Panel Testimony), pp. 29-34.

[363] Hearing Transcript, pp. 47-81.

[364] Case 21-M-0541, supra, Order Releasing Audit Report.

[365] Id., Order Approving Implementation Plan with Modification.

[366] Id., CHGE Implementation Plan June 2025 Update (filed June 30, 2025). This is an improvement over its September 30, 2024, update, in which the Company reportedly had implemented 25 recommendations (Hearing Transcript, p. 78) and its March 2025 update in which it had reportedly implemented 31 implemented recommendations.

Inasmuch as the Company remains subject to the updated implementation plan approved with modifications in the Order issued in Case 21-M-0541, no further action is necessary at this time.[367]

Make-Whole Provision

Because this Order is being issued after July 1, 2025, a make-whole provision is warranted pursuant to which the Company will recover under-collections or refund over-collections in sales revenue resulting from the Company's agreement to extend the suspension period to accommodate settlement negotiations in these proceedings. The revenue differences will be recovered or credited, with applicable surcharges and carrying charges, over the remaining months of RY1 and RY2.[368]

CONCLUSION

Based on our thorough evaluation of the record in these proceedings, we adopt the terms of the Joint Proposal. The three-year Rate Plan provides for rates that are just and reasonable and, when considered in conjunction with the Rate Plan's other terms and conditions, satisfies the Commission's concern that, overall, the plan is in the public interest.

The Commission orders:

1. The rates, terms, conditions, and provisions of the Joint Proposal dated May 13, 2025, filed in these proceedings, and attached hereto as Attachment A, are adopted and

[367] 2024 Rate Order, p. 98.

[368] Joint Proposal, pp. 8-9.

incorporated herein to the extent consistent with the discussion herein as part of this Order.

2. Central Hudson Gas & Electric Corporation is directed to file cancellation supplements, effective on not less than one day's notice, on or before August 21, 2025, cancelling the tariff amendments and supplements listed in Attachment B to this Order.

3. Central Hudson Gas & Electric Corporation is directed to file, on not less than 5 days' notice, to take effect on September 1, 2025, on a temporary basis, such tariff changes as are necessary to effectuate the terms of this Order for Rate Year 1, the twelve-month period ending June 30, 2026, and to incorporate any tariff amendments that were previously approved by the Commission since the tariff amendments listed in Attachment B were filed, except for those related to the make-whole provisions adopted in this Order.

4. Central Hudson Gas & Electric Corporation shall serve copies of its Rate Year 1 filings on all active parties to these proceedings. Any party wishing to comment on the tariff amendments may do so by electronically filing its comments with the Secretary to Commission and serving its comments upon all active parties within 14 days of service of the proposed amendments. The amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission.

5. Central Hudson Gas & Electric Corporation is directed to file, on not less than two days' notice, to take effect on October 1, 2025, on a temporary basis, such further tariff revisions as are necessary to effectuate the make-whole provisions adopted in this Order. Central Hudson Gas & Electric Corporation shall serve copies of its filings on all parties in to these proceedings. Any party wishing to comment on

the compliance filings may do so by electronically filing its comments with the Secretary to the Commission and serving its comments upon all parties within 14 days after service of the Company's proposed amendments. The amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission.

6. Central Hudson Gas & Electric Corporation is directed to file, on not less than 30 days' notice, to take effect on July 1, 2026, on a temporary basis, such further tariff changes as are necessary to effectuate the terms of this Order for Rate Year 2, the twelve-month period ending June 30, 2027, as discussed in the body of this Order. The amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission.

7. Central Hudson Gas & Electric Corporation is directed to file, on not less than 30 days' notice, to take effect on July 1, 2027, on a temporary basis, such further tariff changes as are necessary to effectuate the terms of this Order for Rate Year 3, the twelve-month period ending June 30, 2028, as discussed in the body of this Order. The amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission.

8. The requirements of Public Service Law §66(12)(b) and Title 16 of the New York Codes, Rules and Regulations §720-8.1 that newspaper publication be completed prior to the effective date of the amendments for Rate Year 1 are waived; provided however, that Central Hudson Gas & Electric Corporation shall file with the Secretary of the Commission, no later than six weeks following the effective date of the amendments, proof that notice to the public of the changes set forth in the amendments has been published once a week for consecutive weeks in one or more newspapers having general circulation in the

service territory and areas affected by the amendments. The requirements of Public Service Law §66(12)(b) and Title 16 of the New York Codes, Rules and Regulations §720-8.1 are not waived for tariff changes necessary to implement the rate plans in Rate Years 2 and 3, or with respect to tariff filings in compliance with this Order made in subsequent years.

9. In the Secretary's sole discretion, the deadlines set forth in this Order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least three days prior to the affected deadline.

10. These proceedings are continued.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

Attachment A

NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service	Case 24-E-0461

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	Case 24-G-0462

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JOINT PROPOSAL

May 13, 2025

TABLE OF CONTENTS

APPENDICES

Appendix A:	Electric and Gas Income Statements and Rate Base
Appendix B:	Make Whole Calculation
Appendix C:	Net Plant Targets and Methods for Calculating Actual Net Plant Revenue
Appendix D:	Format for Capital Expenditure Reports
Appendix E:	Annual Capital Budget
Appendix F:	Listing of Deferrals
Appendix G:	Major Storm Reserve and Non-Major Storm Expense
Appendix H:	Rate Adjustment Mechanism
Appendix I:	Net Deferred Accounts Available for Moderation
Appendix J:	Revenue Matched Items
Appendix K:	Depreciation Factors and Rates
Appendix L:	Capital Structures and Allowed Rate of Return
Appendix M:	New, Modified and Continuing Reporting Requirements
Appendix N:	Electric and Gas Forecasts of Sales, Customers and Revenues
Appendix O:	Electric and Gas Rate Design and Billing Determinants
Appendix P:	Electric and Gas Revenue Allocation
Appendix Q:	Electric and Gas Estimated Bill Impacts
Appendix R:	Electric and Gas RDM Billing Determinants and Targets by Rate Year and by Class
Appendix S:	Electric Reliability Performance Mechanism
Appendix T:	Gas Safety Metrics
Appendix U:	Gas Safety Violations Performance Measure
Appendix V:	Customer Service Performance Indicators
Appendix W:	Outreach and Education Plan
Appendix X:	Earnings Adjustment Mechanisms

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JOINT PROPOSAL

I. INTRODUCTION

This Joint Proposal ("Proposal" or "JP") providing for the resolution of all issues in the above-captioned cases is made mutually by Central Hudson Gas & Electric Corporation ("Central Hudson" or "Company"); the New York State Department of Public Service Staff ("Staff"); Multiple Intervenors ("MI"); Walmart; and the other entities whose signatures appear below and other parties whose signatures are or will be attached to this Proposal (collectively, the "Signatories" or the "Signatory Parties").[1]

II. PROCEDURAL HISTORY

A. The Rate Case Proceedings

On July 18, 2024, the New York State Public Service Commission ("Commission" or "PSC") issued an Order Establishing Rates for Electric and Gas Service, which set

[1] Although not signatories to this Proposal, the Public Utility Law Project of New York, Inc. ("PULP"), the Utility Intervention Unit of the Department of State, Division of Consumer Protection ("UIU"), Dutchess County, and the Town of Olive Conservation Advisory Council ("Town of Olive") have stated that they do not oppose this Proposal.

forth a one-year rate plan for the Company for the period from July 1, 2024 through June 30, 2025.[2]

On August 1, 2024, Central Hudson filed tariff leaves and testimony with the PSC in support of proposed increases to its electric and gas delivery revenues based on a Rate Year comprised of the 12 months ending June 30, 2026 ("Rate Year"). Central Hudson also included select financial information for two additional rate years as Attachment B to its filing letter.[3] Central Hudson's proposed delivery rates were designed to produce an electric delivery revenue increase of approximately $69.4 million and a gas delivery revenue increase of approximately $27.0 million. As part of its filing, Central Hudson proactively applied existing net regulatory liability balances of approximately $22.2 million for electric and $11.7 million for gas to the proposed increases to moderate rate increases during the Rate Year. After moderation, the proposed delivery rate increases were $47.2 million for electric and $15.3 million for gas, resulting in base delivery revenue increases of 8.6% and 7.5%, respectively, or total bill increases of 5.3% and 5.9%, respectively, for an average residential customer.

On August 19, 2024, the Commission suspended the Company's proposed tariff leaves through December 31, 2024.[4] Discovery was commenced by Staff and other parties. To date, Staff has tendered a total of 732 multi-part information requests ("IRs")

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2 Cases 23-E-0418 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Order Establishing Rates for Electric and Gas Service (Jul. 18, 2024) ("2024 Rate Plan").

3 Cases 24-E-0461 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Cover Letter Attachment B (Aug. 1, 2024).

4 Cases 24-E-0461 et al., Notice of Suspension of Effective Date of Major Rate Changes and Initiation of Proceedings (Aug. 19, 2024). By notice issued on December 11, 2024, the Company's proposed tariff leaves were suspended through June 30, 2025. Cases 24-E-0461 et al., Notice of Further Suspension of the Effective Date of Major Rate Changes (Dec. 11, 2024).

to the Company; UIU tendered 41 IRs; PULP tendered 63 IRs; MI tendered 64 IRs; Communities for Local Power ("CLP") tendered 31 IRs; Dutchess County tendered 28 IRs; the Town of Olive tendered 19 IRs; Representative Josh Riley tendered 17 IRs; and Assemblymember Sarahana Shrestha tendered five IRs.

Administrative Law Judges ("ALJs") Leah Amyot and Erika Bergen were appointed to conduct the rate proceedings to review the Company's rate filing. On September 4, 2024, the ALJs convened a Procedural and Technical Conference during which, among other things, a litigation schedule was proposed and adopted in a subsequent ruling.[5]

On or about November 22, 2024, direct testimony was filed by Staff; UIU; MI; Dutchess County; Walmart; PULP; CLP; and the Office of Assemblymember Sarahana Shrestha. On December 18, 2024, rebuttal testimony was filed by the Company; Staff; and MI.

Consistent with the Commission's Settlement Guidelines[6] and Title 16 of the New York Codes, Rules and Regulations ("NYCRR"), Section 3.9, the Company filed with the Commission and served on all parties a Notice of Impending Settlement Negotiations on December 10, 2024.[7] Settlement negotiations began on December 20, 2024 and continued on January 7, 13, 14, 17, 21, 24, 29, and 30; February 4, 5, 11, 14, 19, 26,

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5 Cases 24-E-0461 et al., Ruling on Schedule (Sep. 5, 2024).

6 32 NYPSC 71; Case 90-M-0255 et al. - Proceeding on Motion of the Commission Concerning its Procedures for Settlement and Stipulation Agreements, filed in C11175, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines, Opinion 92-2 (Mar. 24, 1991) ("Settlement Guidelines").

7 Cases 24-E-0461 et al., Notice of Impending Settlement Negotiations (Dec. 10, 2024).

27, and 28; March 4, 7, 11, 17, and 24; and April 1, 3, 8, 10, 15, 22, and 24.[8] Participants included representatives of the Company, Staff, MI, PULP, UIU, CLP, Dutchess County, Walmart, Town of Olive, and other interested parties. All negotiations were held either in person or via videoconference (with teleconference capabilities), or both. All settlement negotiations were subject to the Commission's Settlement Guidelines and 16 NYCRR Section 3.9, and appropriate notices for all negotiating sessions were provided to the parties.

On December 20, 2024, the Company filed a letter with the Commission: (1) consenting to an extension of the suspension period through and including August 31, 2025, in light of ongoing settlement negotiations, subject to a "make whole" provision that would keep the Company and its customers in the same financial position they would have been in absent the extension; and (2) requesting that the evidentiary hearings in these cases, previously scheduled to commence on January 7, 2025, be postponed accordingly.[9] On December 30, 2024, the ALJs issued a ruling which postponed the evidentiary hearing to March 4, 2025 in light of the parties' settlement efforts.[10]

By letter dated February 20, 2025, the Company requested a continued postponement of the evidentiary hearing and agreed to further extend the suspension period through and including September 30, 2025, subject to a "make whole"

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[8] The settlement negotiations also included over 11 additional "working group" meetings on specific issues that were held with the consent of all parties.

[9] Cases 24-E-0461 et al., Request to Postpone Evidentiary Hearing and Extend Suspension Period (Dec. 20, 2024).

[10] Cases 24-E-0461 et al., Ruling Postponing Evidentiary Hearing (Dec. 30, 2024).

provision.[11] On February 25, 2025, the ALJs issued a ruling which postponed the evidentiary hearing to April 28, 2025, subject to a number of conditions.[12] On March 4, 2025, Chief ALJ Dakin Lecakes appointed ALJ Ashley Moreno as settlement judge to oversee the continuation of settlement developments. By notice issued on March 24, 2025, three in-person public statement hearings were scheduled for April 29 and 30, 2025 to provide customers with an opportunity to comment on the Company's rate proposals.[13]

On April 11, 2025, the Company filed a letter with the Commission requesting a further postponement of the evidentiary hearing and consenting to further extend the suspension period by an additional 31 days, through and including October 31, 2025, subject to a "make whole" provision to facilitate settlement discussions.[14]

B. The Settlement

The settlement negotiations were successful and have resulted in this JP between the Company, Staff, MI, and Walmart, which is presented to the Commission for its consideration. The Signatory Parties have developed a comprehensive set of terms and conditions for a three-year rate plan for Central Hudson's electric and gas services. The terms of this Proposal, as set forth below and in the attached Appendices, balance the varied interests of the Signatory Parties while mitigating rate impacts to customers, and support the goals of the Climate Leadership and Community

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11 Cases 24-E-0461 et al., Request to Further Postpone Evidentiary Hearing and Extend Suspension Period (Feb. 20, 2025).

12 Cases 24-E-0461 et al., Ruling Further Postponing Evidentiary Hearing (Feb. 25, 2025).

13 Cases 24-E-0461 et al., Notice Soliciting Comments and Announcing In-Person Public Statement Hearings (Mar. 24, 2025).

14 Cases 24-E-0461 et al., Request to Further Postpone Evidentiary Hearing and Extend Suspension Period (Apr. 11, 2025).

Protection Act ("CLCPA") while ensuring the Company's ability to continue to provide safe and reliable service.

Pursuant to the settlement discussions, the Signatories recommend that the rates and surcharges of Central Hudson be determined in accordance with the following understandings, principles, qualifications, terms and conditions set forth in this JP and in the attached Appendices.

III. TERM AND EFFECTIVE DATE OF RATE CHANGES

The term of this JP is three years, commencing July 1, 2025, and continuing until June 30, 2028. Agreement among the Signatories to the start of the term resulted from the settlement negotiations. The three successive 12-month periods, or Rate Years, ending on June 30, 2026, June 30, 2027, and June 30, 2028, shall be referred to as "Rate Year 1," "Rate Year 2," and "Rate Year 3," respectively. The JP and related Appendices set out the terms, revenue, and expense amounts for Rate Year 1, Rate Year 2, and Rate Year 3 agreed to by the Signatories. The provisions of Rate Year 3 will, unless otherwise specified herein, remain in effect until superseding rates and/or terms become effective.

Nothing herein precludes Central Hudson from filing a new general electric or gas rate case prior to June 30, 2028, for rates to be effective on or after July 1, 2028. The Company will not initiate rate changes to become effective prior to July 1, 2028, subject to certain exceptions as discussed in Section XXV.A of this JP.

IV. REVENUE REQUIREMENTS

A. Revenue Requirements

The revenue requirements for Rate Year 1, Rate Year 2, and Rate Year 3 are shown in the Electric and Gas Income Statements set forth in Appendix A.

B. Delivery Revenue Increases

The base delivery revenue increases are displayed in the table below.

Delivery Revenue Increases*			
	Rate Year 1 ($000,000)	Rate Year 2 ($000,000)	Rate Year 3 ($000,000)
Electric	$46.4	$30.7	$21.7
Gas	$19.0	$13.9	$16.9

* Excludes Revenue Taxes

C. Electric Bill Credits

To achieve rate moderation, electric bill credits of $16.7 million will be applied in Rate Year 1 using available regulatory liabilities. To achieve rate moderation in Rate Years 2 and 3, electric bill credits of $15.8 million in Rate Year 2 and $3.0 million in Rate Year 3 will be applied using available net regulatory liabilities and an electric rate base credit that originated from the sale of generation assets, as further described in Section V.F. The bill credit will be allocated to each service class in proportion to class responsibility for the delivery rate increase, exclusive of the legacy hydro revenue imputation. The allocated credits will be refunded to customers on a kilowatt-hour or kilowatt basis through the existing Electric Bill Credit Mechanism.

D. Gas Bill Credits

To achieve rate moderation, gas bill credits of $4.5 million in Rate Year 1, $2.5 million in Rate Year 2 and $1.9 million in Rate Year 3 will be applied using available regulatory liabilities. The bill credits will be allocated to each service class in proportion to class responsibility for the overall delivery rate increase. The allocated credits will be refunded to customers on a Ccf basis through the existing Gas Bill Credit Mechanism.

E. Delivery Revenue and Total Bill Increases After Moderation

After applying the rate moderation described in Sections IV.C and IV.D, the resulting delivery revenue increases are shown in the table below:

	ELECTRIC			GAS		
($000,000)	RY1	RY2	RY3	RY1	RY2	RY3
Revenue Requirements (Excluding Rev Tax)	$46.4	$30.7	$21.7	$19.0	$13.9	$16.9
% on Delivery Revenues	8.6%	5.1%	3.4%	11.5%	7.6%	8.7%
% on Total Revenues	4.5%	2.8%	1.9%	7.1%	4.9%	5.6%
Use of Moderation	$(16.7)	$(15.8)	$(3.0)	$(4.5)	$(2.5)	$(1.9)
Prior Year Moderation Reversal	-	$16.7	$15.8	-	$4.5	$2.5
Revenue Requirement After Moderation	$29.7	$31.6	$34.5	$14.5	$15.9	$17.5
% on Delivery Revenues After Moderation	5.5%	5.3%	5.3%	8.8%	8.7%	9.0%
% on Total Revenues After Moderation	2.9%	2.9%	3.0%	5.4%	5.6%	5.8%

F. Make Whole Provision

In the event that Commission approval of this Proposal occurs after July 1, 2025, Central Hudson will recover or refund any revenue under-collections or over-collections, respectively, resulting from any requested extension of the suspension period through a make whole provision. The make whole provision is designed to ensure that, by June 30, 2027, Central Hudson and its customers are restored to the same financial position had new delivery rates gone into effect on July 1, 2025.

The Company will calculate any revenue adjustments as the difference between: (1) sales revenues the Company would have billed at new rates during the extension of the suspension period; and (2) the same level of sales revenues at current rates. The revenue adjustments would include all applicable surcharges and carrying charges, would be subject to reconciliation in accordance with all applicable adjustment mechanisms, and will be collected or refunded over the remainder of Rate Years 1 and 2 measured from the date new rates are billed. In addition, the amortization of net deferrals reflected in the final Commission order adopting the terms of this JP will commence consistent with the month in which rates become effective, on an earnings neutral basis. The make whole will be recovered or refunded through the existing Miscellaneous rate surcharge, separately for electric and gas. An example is set forth in Appendix B.

V. ACCOUNTING MATTERS

A. Net Plant Targets, Reconciliation, Deferral Accounting and Reporting Requirements

1. Components of Net Plant

Actual Net Plant and the Net Plant Targets have four components: (1) the Average Electric or Gas Net Plant; (2) the Average Electric or Gas Non-Interest Bearing Construction Work in Progress; (3) the Average Common Net Plant allocated to Electric or to Gas; and (4) the Average Common Non-Interest Bearing Construction Work in Progress allocated to Electric or to Gas.

2. Electric and Gas Net Plant Targets

The electric and gas net plant and depreciation expense targets are set forth in Appendix C, Schedule 1. The targets include an adjustment to remove the effects of the Solar on Company Facilities capital investment that was included in the development of revenue requirements. Additionally, the Company will defer the revenue requirement effect of the capital investment for future return to customers as noted in Section V.B.1.xxx. These targets are applicable only to the time periods specified and not any subsequent period, notwithstanding any other provision of this JP. The actual average electric and gas net plant balances and depreciation expense at the end of each Rate Year will be calculated using the calculation methods described in Appendix C, Schedule 2.

3. Net Plant Target Reconciliations

The actual electric and gas net plant and depreciation expense will be reconciled to the combined electric and gas net plant and depreciation expense targets for Rate Year 1, Rate Year 2, and Rate Year 3 on a cumulative basis at the end of Rate Year 3.

4. Deferral for the Benefit of Ratepayers

If at the end of Rate Year 3 the cumulative revenue requirement impact from net plant and depreciation expense differences is negative, the Company will defer the revenue requirement impact for the benefit of customers. If at the end of Rate Year 3 the cumulative revenue requirement impact is positive, no deferral will be made. Carrying charges at the pre-tax rate of return ("PTROR") will be applied by the Company to the amount deferred from the end of Rate Year 3 until the effective date of the Company's next rate order.

5. Capital Expenditures Reporting Requirements

The Company will continue to file with the Secretary by March 1 of each year a report on its capital expenditures during the prior calendar year using a format similar to that presented in Appendix D to this JP. In addition, the Company will continue to file its five-year capital investment plan with the Secretary to the Commission ("Secretary") annually by July 1. The annual report shall include an explanation of any cost variance between the approved work order authorization and an actual expenditure greater than 10% for any single project identified in the Company's Major Capital Project Report shown in Appendix D, Schedule 1. Any substantive changes to a project will be discussed. Projects and programs listed in Appendix D, Schedule 1-3 will be identified by name and applicable funding project or work order number. The capital investment plan agreed to in this Proposal is set forth in Appendix E.

The Company will file with the Secretary quarterly capital variance reports within 45 days of the end of each quarter using a format similar to that presented in Appendix D, Schedule 3. In lieu of a report for the fourth quarter, the Company will submit the quarterly (Appendix D, Schedule 3) and annual (Appendix D, Schedule 1 and Schedule 2) reports by March 1 of the next calendar year. These variance reports will provide cost data at the funding project level, which is rolled-up into the identified programs for each category.

For physical and cybersecurity capital projects, on a quarterly basis, the Company will file with the Secretary a report that indicates (1) when physical or cybersecurity projects reach significant milestones, are merged with other projects, or are discontinued and (2) when significant changes are made to cybersecurity-related full-time equivalents. In addition, twice a year, the Company will provide a status and update report on project spending and project schedules for each physical and cybersecurity project and program. The report will highlight and explain significant changes[15] to these projects and programs. These reports will be filed with the Secretary.

Unless expressly stated in this JP, nothing in this JP is intended to alter the Company's flexibility during the term hereof, to alter the timing of, substitute, change, or modify its capital projects.

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[15] For purposes of this reporting, significant changes are: (1) those in either of the key performance indicators of cost estimating performance or schedule performance; (2) those that require Capital Asset Review and Evaluation committee approval; or (3) when project status changes sufficiently to require a detailed Status Report that is currently implemented by Central Hudson.

B. Deferral Accounting[16]

1. <u>Effective Deferrals</u>

Authorized accounting deferrals include those identified below. A listing of the deferrals, together with a detailed description of the specific deferral method and associated carrying charge for each, can be found in Appendix F.[17] The effective deferrals are included below:

a) AMP Phase II;

b) Incremental costs of litigation regarding claims of exposure to asbestos at Company facilities;

c) Asset Retirement Obligation Depreciation and Accretion Expense;

d) Call Center Legislation – The Company is authorized to defer, on a Rate Year basis, incremental costs incurred to comply with Chapter 107 of the Laws of 2025, which relates to call centers for gas and electric corporations and will impact call center staffing location and operations, based on the following structure: (1) 100% deferral of incremental expenditures associated with the hiring of internal or external resources, including but not limited to labor, training, equipment, and office space up to $7.5 million; (2) 50% deferral of incremental expenditures between

[16] All deferral authority referenced in the JP is without application of the Commission's traditional three-part test for deferral accounting or deferral petition requirements. For purposes of the JP, unless otherwise expressly defined, revenue requirement effect includes revenue, expense, return on capital expenditures, depreciation, applicable property taxes and any other associated taxes and fees.

[17] While the listing of deferrals in Appendix F is intended to be comprehensive at the time of the JP, the Signatories recognize that other authorized deferral accounting mechanisms may have inadvertently been excluded from this listing. To that end, the Signatories recognize that, except as expressly modified within this JP, the Company is authorized to continue its use of all accounting deferrals for revenues, expenses and costs, as specified in the 2024 Rate Plan, or for which Commission authorization for deferral accounting is currently effective, whether by reason of a Commission order, policy of general applicability, or a Commission determination with specific reference to the Company.

$7.5 million and $8.5 million; and (3) a limit on the deferral of incremental expenditures set at $8.5 million per Rate Year. Carrying charges will be at the PTROR. Refer to Appendix F, Schedule 4 for an illustrative example;

e) Incremental Costs Associated with Case 14-M-0101;

f) CDG Consolidated Billing Deferral;[18]

g) Clean Energy Fund costs (including expired Renewable Portfolio Standards ("RPS"), Energy Efficiency Portfolio Standard ("EEPS") and System Benefits Charge ("SBC"));

h) Climate Change Resilience Plan – The Company is allowed to defer only the costs of necessary consultants retained to develop a second round Climate Change Resilience Plan as required by Public Service Law ("PSL") § 66(29)(f). The Company shall not use this deferral for the costs of any resilience projects or programs;

i) Revenue Requirement Effect of Cloud-Based or Software as a Service ("SAAS") Solutions – Refer to Appendix F, Schedule 2 for an illustrative example. Additionally, in the event that a deferral is recorded, the Company will file a notice with the Secretary that identifies the project and calculates the deferral, including adjustments for purposes of measuring the net plant targets. This notice will be in lieu of a deferral petition and would not be subject to the Commission's traditional three-part deferral test or its successor;

j) Credit/Debit Card Fees and Walk-In Center Fees;

[18] Case 19-M-0463 - In the Matter of Consolidated Billing for Distributed Energy Resources, Order Regarding Consolidated Billing for Community Distributed Generation (Dec. 12, 2019) at page 19.

k) Danskammer Gas Revenue;

l) Deferred Temporary Metro Transit Bus Tax Surcharge;

m) Deferred Unbilled Revenues;

n) Deferred Unrealized Losses/Gains on Derivatives;

o) Deferred Vacation Pay Accrual;

p) DEI – Proceeding to Review Utilities' Diversity, Equity and Inclusion Practices (Case 22-M-0314);

q) Earnings Adjustment Mechanisms ("EAMs") – Electric;

r) EAMs – Gas;

s) Earnings Sharing Mechanism as set forth in Section VII;

t) Economic Development – Electric;

u) Energy Efficiency – Electric and Gas;

v) Energy Efficiency and Heat Pump – Amortization of Regulatory Asset;[19]

w) Energy Efficiency Exemptions;

x) Revenue Requirement Effect of Energy Storage Projects;[20]

y) Deferral of Environmental Site Investigation and Remediation ("SIR") Costs;

z) Electric Vehicles ("EVs") – Fast Charge Incentive;

aa) EVs – Time of Use ("TOU");[21]

bb) EV Make Ready Program Light Duty – Incremental New Business Capital Costs;

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[19] Carrying charges are no longer applicable because the unamortized regulatory asset is included in the development of rate base beginning July 1, 2025.

[20] Case 17-E-0459 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Order Approving Rate Plan (Jun. 14, 2018) Attachment 1 - Joint Proposal at page 28.

[21] Case 18-E-0206 - Tariff filings to Effectuate the Provisions of Public Service Law Section 66-o (Residential Electric Vehicle Charging Tariff), Order Rejecting Tariff Filings and Directing Tariff Revisions (Nov. 15, 2018) at page 10.

cc) EV Make Ready Program Light Duty – Incremental O&M and Capital Costs Excluding New Business;

dd) EV Make Ready Program Medium/Heavy Duty – Incremental New Business Capital Costs;

ee) EV Make Ready Program Medium/Heavy Duty – Incremental O&M and Capital Costs Excluding New Business;

ff) Executive Short Term Incentive Compensation – For Rate Year 1, the Company is authorized to defer executive short term incentive compensation expense, contingent on Staff's acceptance of the Company's implementation of Recommendation 2.7 as completed in Case 21-M-0541 prior to the end of Rate Year 1, with carrying charges at the PTROR. The revenue requirement includes executive short term incentive compensation expense for Rate Year 2 and Rate Year 3; however, if Recommendation 2.7 is not completed by the end of the respective rate year, the Company will defer the rate allowance for future return to customers, with carrying charges at the PTROR;

gg) External Rate Case Expenses;

hh) FAS 109;

ii) FERC Jurisdictional Proceedings – Incremental Costs and Potential Outcomes Regarding Hydro Facilities;

jj) FERC Wholesale Delivery Service Revenues;

kk) Finance Charges and Reconnection Fee Revenue Deferral;

ll) Funded Status Adjustment of Pension/OPEB Plans;

mm) Gas Planning Proceeding – Gas Long-Term Plan – The Company is authorized to defer up to $665,000 in Rate Year 3 related to preparing its next Gas Long-Term Plan as required by Case 20-G-0131;

nn) Gas Long-Term Plan Proceeding – PA Consulting – The Company's deferral of costs associated with PA Consulting's services regarding the Company's Gas System Long-Term Plan in Case 23-G-0676 is subject to the limitation set forth in Section XXIII.A. below;

oo) Governmental, Legislative and Other Regulatory Actions – The Company is authorized to defer the revenue requirement effect of any governmental, legislative, accounting, regulatory, tax or applicable tax rates, fees, government-mandated action or other regulatory actions in a Rate Year whose impact in aggregate is greater than 10 basis points for either the electric department or the gas department, with carrying charges at the PTROR;

pp) Heat Pump Program;

qq) Integrated Energy Data Resource Costs;[22]

rr) Interconnection Policy Working Group;

ss) Legacy Hydro Revenue;

tt) Low Income Bill Discount Program / Energy Affordability Program;

uu) Low Income Waiver of Reconnection Fee;

vv) Major Storm Reserve as described in Appendix G;

ww) Major Storm Amortization;[23]

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22 Case 20-M-0082 - Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data, Order Implementing an Integrated Energy Data Resource (Feb. 11, 2021) at pgs. 17-22.

23 Carrying charges are no longer applicable because the unamortized regulatory asset is included in the development of rate base beginning July 1, 2025.

xx) Make Whole Provision;

yy) Net Lost Revenues associated with the Merchant Function Charge ("MFC");

zz) Net Plant and Depreciation Targets as described in Section V.A;

aaa) Non-Major Storm Expense – Non-Major Storm expense is defined as costs incurred for restoration of outages caused by any adverse weather event that does not meet the criteria of a major storm. The Company will reconcile actual non-major storm expense to the rate allowance at the end of each Rate Year on a cumulative basis. At the end of each Rate Year, if the Company has a net underspend, a deferral for return to customers will be recorded; if the Company has a net overspend, no deferral will be recorded. Any cumulative underspending at the end of Rate Year 3 will be deferred for future return to customers, with carrying charges at the PTROR. Refer to Appendix F, Schedule 5 for an illustrative example;

bbb) Non-Pipe Alternative Projects;

ccc) Non-Wire Alternative Projects;

ddd) NYS Corporate Tax Change;

eee) Post Employment Benefits Other than Pensions ("OPEBs") under Accounting Standards Codification Topic 715 (formerly Statement of Financial Accounting Standards No. 106);

fff) Pension and OPEB Reserve Carrying Charges;

ggg) Pension Expense under Accounting Standards Codification Topic 715 (formerly Statement of Financial Accounting Standards No. 87);

hhh) PermaLock Tapping Tee Assemblies – The Company is authorized to defer the revenue requirement effect of incremental costs, including

O&M and return on and of capital investments, incurred to comply with any future directives in Case 23-G-0083 regarding the inspection and/or remediation of PermaLock Tapping Tee Assemblies that are not otherwise addressed within generic proceedings, with carrying charges at the PTROR;

iii) Platform Service Revenues;

jjj) Pole Attachment Revenue & CATV/Broadband Make Ready;

kkk) Property Taxes – For each Rate Year, the difference between the rate allowance for property tax expense (including school, county, city, town, village and special franchise) and actual property tax expense on a Rate Year basis will be deferred for future recovery, or returned to customers, with carrying charges at the PTROR. Differences will be shared 90/10 between customers and the Company, respectively; provided, however, that the Company's pre-tax loss or gain will be limited to five basis points per (electric and gas) department for each Rate Year;

lll) PSC Initiated or Required Management and Operation Audit Costs;

mmm) Purchased Electric Costs and Purchased Gas Costs (Commodity Related Deferrals);

nnn) Rate Adjustment Mechanism – Electric and Gas as described in Appendix H;

ooo) Rate Moderator – Electric;

ppp) Rate Moderator – Gas;

qqq) Renewable Energy Access and Community Help;

rrr) Research and Development costs under Commission Technical Release No. 16;

sss) Reforming the Energy Vision ("REV") Demonstration Projects;

ttt) Revenue Decoupling Mechanism – Electric;

uuu) Revenue Decoupling Mechanism – Gas;

vvv) Right of Way Maintenance – Distribution – The revenue requirement set forth in this Proposal includes $26.3 million of expense for distribution right of way tree trimming expenditures in each of Rate Year 1, Rate Year 2, and Rate Year 3. Actual expenditures will be compared to the sum of the allowances over the three-year term of this Proposal, on a cumulative basis. Any cumulative underspending at the end of Rate Year 3 will be deferred for future return to customers, with carrying charges at the PTROR. Refer to Appendix F, Schedule 3 for an illustrative example;

www) Sales Tax Refunds and Assessments;

xxx) Solar on Company Facilities – The Company will defer the revenue requirement effect of the capital investments associated with installing solar on company facilities included in the development of revenue requirements for future return to customers;

yyy) Statewide Solar for All;

zzz) Stray Voltage Program Costs;

aaaa) Supplemental AMI Gas Study – The Company is authorized to defer the costs associated with a Supplemental AMI Gas Study, up to $100,000, with carrying charges at the PTROR. The study will evaluate the potential deployment of gas-only AMI endpoints and remote methane detectors in areas where neighboring utilities maintain an electric franchise in the southern portions of the Company's gas service territory;

bbbb) TCJA Non-Asset Based EDFIT Balance Amortization;

cccc) Theoretical Reserve Amortization;[24]

dddd) Uncollectible Reserve Deferral – The Company is authorized to record a deferral to offset the uncollectible reserve on its balance sheet. This deferral is strictly an accounting change and will not impact the revenue requirement or customer bills;

eeee) Uncollectible Write-Offs and Collection Agency Fees; and

ffff) Utility Thermal Energy Network pilot project costs as authorized by orders in Case 22-M-0429.

2. Expiring Deferrals

The accounting deferrals for the following revenues, expenses and costs will expire on the effective date of a Commission order in these proceedings:

a) AMP Phase I;

b) Roadway Excavation Quality Assurance Act;

c) Utility Asset Sale to TRANSCO Carrying Charges;

d) Long Term Debt – Variable Rate NYSERDA Series B Bond; and

e) Customer Benefit Fund.

C. Deferral Extension/Continuation

For the avoidance of doubt, unless expressly stated otherwise in this JP, the deferrals authorized or permitted consistent with this JP will not terminate by reason of

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24 Carrying charges are no longer applicable because the unamortized regulatory asset is included in the development of rate base beginning July 1, 2025.

the end of Rate Year 3, but they shall continue until such time as they are superseded or expressly modified or revoked.

D. Right to Petition

The Company may petition the Commission for authorization to defer extraordinary expenditures or revenue loss not otherwise addressed by this JP, potentially including items discussed above. Other Signatories reserve the right to respond to any such petition as each such Signatory may see fit. To the extent that new mandatory regulatory, legislative or accounting changes, tax law changes, other regulatory policy changes, pandemic or public health related events, or other events materially affecting the Company's level of revenues or cost of providing service not specifically addressed herein become effective or occur during this Rate Plan, any Signatory hereto may petition the Commission to adjust the Company's rates accordingly.

E. Cost Recovery Mechanisms in Generic Proceedings

The Signatories agree that incremental costs, including O&M and capital investments, related to compliance with the following proceedings are neither included in the revenue requirement for Rate Year 1, Rate Year 2 or Rate Year 3, nor were the costs known or estimable at the time of this agreement. To the extent necessary, the Signatories recognize that the Company may request cost recovery mechanisms within the proceedings listed below:

(1) Coordinated Grid Planning Proceeding - Case 20-E-0197;

(2) Grid of the Future - Case 24-E-0165; and

(3) PSL § 119-d - Case 25-M-0051.

F. Projected Net Deferred Regulatory Credits

Actual July 1, 2025, balances for the items shown on Appendix I will be offset against each other at the time of the Commission's Order in these proceedings, with the net deferred credit balance available for rate moderation. Any unused balance shall remain deferred, with carrying charges at the PTROR.

Additionally, as of July 1, 2026, the Company will reflect an additional electric regulatory liability of $15.8 million available for rate moderation. This credit balance is equivalent to approximately 50% of the balance currently included in rate base in Account 108.50, which was initially recorded as a result of the sale of the Company's legacy generation. The credit balances noted above will be removed from rate base and established as a regulatory liability (credit) effective July 1, 2026, when the additional moderation is needed for the purposes of providing customer bill credits. Any unused regulatory credit balance shall remain deferred, with carrying charges at the PTROR.

G. Revenue Matched Rate Allowances

Rate allowances for revenue matched items are set forth in Appendix J.

H. Fortis Overhead Allocation Methodology

Subject to the cost allocation requirements set forth in the Order Authorizing Acquisition Subject to Conditions issued on June 26, 2013, in Case 12-M-0192 ("Acquisition Order"),[25] the Company will report any changes in the allocation methodology of Fortis overhead costs within 60 days after the revised cost allocation effective date. The Company will also report any change in the Fortis Overhead

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[25] Case 12-M-0192 - Joint Petition of Fortis Inc. et al. and CH Energy Group, Inc. et al. for Approval of the Acquisition of CH Energy Group, Inc. by Fortis Inc. and Related Transactions, Order Authorizing Acquisition Subject to Conditions (Jun. 26, 2013).

Allocation Methodology in its Annual Report of Affiliate Transactions filed on April 1 of each year pursuant to the Acquisition Order.

I. Depreciation

The average service lives, net salvage factors and life tables used in calculating the theoretical depreciation reserve and in establishing depreciation expense are set forth in Appendix K. The Company is authorized to use these factors until new factors are approved by the Commission.

VI. <u>CAPITAL STRUCTURE AND RATE OF RETURN</u>

A. Capital Structure and Return on Equity

The common equity ratio is 48% for all three Rate Years. The capital structures and cost rates for debt and customer deposits are shown by Rate Year in Appendix L. The allowed return on common equity ("ROE") is 9.5% for all three Rate Years.

B. Cost of Long-Term Debt and Customer Deposit Rate

The average cost rate of long-term debt is 4.65% for Rate Year 1, 4.87% for Rate Year 2, and 5.01% for Rate Year 3. The Customer Deposit Rate is 3.0% for all three Rate Years.

VII. <u>EARNINGS SHARING MECHANISM</u>

A. Thresholds

The Earnings Sharing Mechanism applicable to the Company is based on the agreed upon ROE of 9.5% as follows:

(1) Actual regulatory earnings at the allowed ROE of 9.5% to 10.0% will be retained by the Company;

(2) Actual regulatory earnings above 10.0% to 10.5% will be shared 50/50 (customers/Company);

(3) Actual regulatory earnings above 10.5% to 11.0% will be shared 75/25 (customers/Company); and

(4) Actual regulatory earnings above 11.0% will be shared 90/10 (customers/Company).

These regulatory earnings sharing percentages shall be maintained until base rates are reset by the Commission. Such calculation will be performed on an annual basis in the same manner as set forth below. Carrying charges at the PTROR will be applied by the Company to the amount deferred at the end of the Rate Year, if applicable, until base rates are reset by the Commission.

In the event there is a stay-out period of less than 12 months, the earnings sharing mechanism will continue and be calculated as shown in Appendix L, Schedule 5. The regulatory Rate of Return will be based on the accumulated regulatory operating income for the period beginning July 1, 2028, through the end of the last month of the stay-out period. Actual average rate base will be developed based on the 12-month period ending at the same date as the end of the stay-out period and adjusted by an operating income ratio factor. This adjustment to the 12 months ended average rate base is intended to align operating income to the level of rate base that generated that income. This factor will be calculated as the ratio of book operating income during the same partial year period in the previous Rate Year to the total book operating income for that Rate Year. The Earnings Base Capitalization adjustment, included in the development of average rate base, will be based on the amount used to set delivery rates.

B. Reporting and Calculation of Actual Regulatory Earnings

Following the end of each Rate Year, the Company will file a report with the Secretary by September 30th initially showing a computation of its actual operating income for the preceding Rate Year on a "per books" basis. The financial consequences of any regulatory performance mechanisms, positive or negative, including from EAMs and other ratemaking exclusions consistent with existing practices, which include but are not limited to, expenses excluded from rate recovery through Commission policy, certain accrual accounting transactions not factored into the determination of revenue requirements, certain expenses that are recorded as non-operating for financial accounting purposes, and appropriate out-of-period charges to income during the Rate Year, will be excluded from the computations of actual regulatory earnings.

The Company's achieved regulatory return on common equity computation will be measured by (electric and gas) department and will reflect the lesser of an equity ratio equal to 50% or Central Hudson's actual average common equity ratio.

The filing will also include a schedule of regulatory deferral balances recorded during the Rate Year that were included in the development of Earnings Base. This schedule will reflect deferred balances at July 1st, the activity recorded during the Rate Year, and the balance at June 30th. Staff will review the schedule provided by the Company and select the deferred accounts that require additional audit. Within 90 days of receipt of Staff's selections, the Company will provide the detailed supporting workpapers.

VIII. <u>NEW, MODIFIED AND CONTINUING REPORTING REQUIREMENTS</u>

A listing of new, modified and continuing reporting requirements is identified in Appendix M. All existing reporting requirements will continue unless expressly stated otherwise.

A. Non-Major Storm Reporting

The Company will track Non-Major Storm expense, which will be subject to audit by Staff. Within 45 days after the end of each quarterly period, the Company will file a report with the Secretary for the preceding quarter with all costs incurred in the Non-Major Storm Expense Account. These costs will be detailed based on one of three types of costs incurred: (1) Class 1 or greater weather events; (2) weather events less severe than a Class 1 event; and (3) the portion of pre-staging costs charged to non-major storm expense per the Pre-Staging and Mobilization parameters of the Major Storm Reserve identified in Appendix G.

For events that the Company is able to specifically track, which at a minimum includes Class 1 weather events or greater, the event and cost details will follow the event level template as provided in Appendix M, Schedule A. For all other non-major storm expenses, cost details will be provided by class of entry (i.e., labor, accounts payable, materials and supplies, etc.). The portion of pre-staging costs charged to expense per the Pre-Staging and Mobilization parameters of the Major Storm Reserve will be provided by the Company by event date.

Additionally, for events that the Company is able to specifically track, the reports will also segregate expenses into two categories (proactive and reactive). Storm expenses for proactive storm events will include circumstances where the Company forecasted the need for advanced preparation of crews and support personnel (i.e., contact center staffing) and captured data related to the adverse weather and restoration preparation efforts. Storm expense for reactive storm events will include circumstances where the forecast did not warrant formal advanced preparation efforts, but interruptions nevertheless occurred, and restoration efforts were required due to adverse weather conditions. An example of this report format is provided in Appendix M, Schedule A.

B. Distribution Right-of-Way Maintenance Reporting

The Company will commence quarterly reporting concerning its Distribution Vegetation Management and Hazard Tree Removal Program in Rate Year 1. The report, which will be filed no later than 45 days after the end of the calendar quarter, will set forth monthly (1) planned and actual miles of trimmed vegetation and (2) budgeted and actual expense for each component of the Distribution Vegetation Management program. For the Hazard Tree Removal program, the Company will provide monthly budgeted and actual expense, the planned and actual number of assigned crews, and the number of actual trees removed. A sample of the report formatting is provided in Appendix M, Schedule B.

C. Discontinued Reporting Requirements

The Signatory Parties agree the following reporting requirements will be discontinued as part of this Proposal:

(1) Monthly Emergency Demand Response Reporting established by the Commission's March 22, 2002, Order Regarding Major Electric Utilities Report in Case 00-E-2054;

(2) Monthly Gas Weather Normalization Adjustment ("WNA") Reporting established by the Commission's March 30, 2010, Order Approving Tariff on a Permanent Basis and Mandating Compliance in Case 08-G-0888, provided that the Company will continue to file an annual statement and associated WNA workpapers when it resets the WNA factors; and

(3) Annual and Quarterly Enterprise Resource Planning - Phase III Project Reporting established by the Commission's November 18, 2021, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan in Cases 20-E-0428 and 20-G-0429.

IX. FORECASTS OF SALES AND CUSTOMERS

The Signatories' agreed-upon electric and gas forecasts for sales volumes and numbers of customers are set forth in Appendix N. Billing determinants corresponding to these forecasts are set forth in Appendix O.

A. Treatment of Danskammer Revenues

The Signatory Parties agree that $1.0 million of service classification ("SC") 11 gas delivery revenues from Danskammer will be imputed in the base delivery revenue utilized to determine the base delivery revenue increases. The imputation will be allocated to each class in proportion to such class's responsibility for overall delivery rate increases. The Company will defer the amount of actual revenues above or below this revenue imputed into base delivery rates for future pass back/collection from customers.

X. COST OF SERVICE, REVENUE ALLOCATION AND RATE DESIGN

A. Cost of Service

1. Next Rate Filing

As part of its next rate filing, the Company will include the following information in its public filings:

(1) A detailed narrative of all classification, allocation and functionalization decisions within the electric and gas embedded cost of service ("ECOS") studies;

(2) A detailed narrative of the development of allocation and functionalization factors, including a description of the underlying data sources utilized;

(3) An analysis of the rate structure resulting from parsing electric SC 13 into standard and high-load factor groupings. To inform the analysis to be

included in the Company's next rate filing, Central Hudson will initiate a collaborative process with interested parties prior to the end of Rate Year 1 to evaluate potential rate design alternatives for the electric SC 3 and SC 13 classes. This process will include analyses and an evaluation of whether a further subdivision of one or more of these classes is warranted. Working with this collaborative, the Company will file a report, prior to the end of Rate Year 2, summarizing the potential solutions analyzed by the collaborative and the positions of the Company regarding the potential solutions. Parties participating in the collaborative process will have the ability to include their positions regarding potential solutions as part of the report; and

(4) An analysis of the rate structure resulting from parsing gas SC 6 separately within the ECOS.

In addition, separate from the ECOS study, the Company will include a load factor analysis of all non-residential gas customers taking service under gas SCs 2, 6 and 13. Based on its analysis, the Company will include in its next rate filing a proposal for future modification to the ECOS study and rate design to ensure accurate apportionment of system costs. Should the Company's proposal include modification of the existing service classification structure or eligibility, such a proposal will also include an estimated timeframe and cost for implementation.

Finally, as part of its next rate filing, the Company will make available to parties in that proceeding its ECOS model and supporting workpapers in native Excel format with all links intact. Supporting workpapers will include any analysis, including but not limited to engineering or accounting analysis, relied upon to support the proposed classification, allocation, and functionalization of costs.

B. Revenue Allocation

1. Electric Revenue Allocation

The Signatories agree on the electric revenue increases, by class, set forth in Appendix P.

2. Gas Revenue Allocation

The Signatories agree to the gas revenue increases, by class, set forth in Appendix P.

3. Next Rate Case Filings

As part of the Company's next rate case filings, the Company's revenue allocation exhibits will show indexed class rates of return both before and after allocation of the proposed electric and gas revenue requirements.

C. Rate Design

1. Electric Rate Design

The Signatories agree to the electric rate design as set forth in Appendix O.

2. Gas Rate Design

The Signatories agree to the gas rate design set forth in Appendix O, which reflects the implementation of the final year of the five-year phase-out of gas declining block rates, effective July 1, 2025. Appendix O also reflects the implementation of the final year of the two-year phase-out of the high volume discount for SC 6 customers, which results in all SC 6 customers being assessed the same volumetric rate. In addition, SCs 15 and 16 (Distributed Generation ("DG") – Commercial and Industrial and DG – Residential) will be eliminated as part of this Proposal.

3. Customer Bill Impacts

The agreed-upon delivery revenue increases have the estimated bill impacts set forth in Appendix Q, reflecting electric and gas bill credits per Section IV.C and D.

XI. PROVISIONS FOR LOW-INCOME CUSTOMERS

A. Energy Affordability Program

This Proposal continues Central Hudson's Energy Affordability Program ("EAP"), which provides bill discounts to eligible customers consistent with the Commission's Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings and waiver of reconnection fees consistent with the Order Approving Implementation Plans with Modifications issued on February 17, 2017, both issued in Case 14-M-0565.[26] The Company will allocate its overcollection of EAP funds at June 30, 2025 to augment approved rate allowances in support of program costs. If program costs exceed the rate allowances and the current overcollection balances during the term of the Rate Plan, the Company will utilize its deferral for any incremental funding.

The bill discount credits are set forth in the electric and gas tariffs and are subject to modification in Case 14-M-0565. The level of funding provided for the bill discount credits and waiver of reconnection fees, subject to symmetrical deferral, is provided below.

Funding ($ in millions)	Rate Year 1	Rate Year 2	Rate Year 3
Electric	$11.0	$11.0	$11.0
Gas	$3.4	$3.4	$3.4
Total	$14.4	$14.4	$14.4

[26] Case 14-M-0565 - Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers, Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings (Aug. 12, 2021).

Any accumulated balances of program under-spending will be deferred for future use in the EAP and carrying charges will be applied at the PTROR. In the event that the funding for the program provided in rates is inadequate to provide benefits to all qualifying customers, the Company is authorized to defer the difference between the rate allowance and the actual expense for future recovery with carrying charges at the PTROR.

B. EAP Outreach

The Company commits to take the following outreach actions aimed at increasing enrollment in the Company's EAP:

- Targeting potential participants by analyzing non-EAP account histories for indications of past or current financial need, such as past receipt of Home Energy Assistance Program ("HEAP") and/or 131-S grants, prior participation in the EAP, abeyances, UGV/DVC, or deferred payment agreements or other payment arrangements. Recipients of pandemic-era relief measures such as RAS, Arrears Management Phase II assistance and Emergency Rental Assistance Payment will also be targeted.
- Targeting will be focused first on zip codes in which the percentage of total residential customers enrolled in the EAP is less than the overall service area participation rate of 4.6%.

During Rate Year 1, the Company will endeavor to achieve enrollment of 15,500 EAP participants and endeavor to maintain that level of EAP participant enrollment in Rate Year 2 and Rate Year 3. Beginning in Rate Year 2, to the extent that EAP participation falls below 15,500, the Company will waive the late fees for the current month for any new self-certifying enrollment as additional incentive for the customers to enroll in the EAP.

C. EAP Audit

The Company will conduct an internal audit of its EAP by the end of Rate Year 2 to verify enrollment records and participant eligibility for the period encompassing September 2021 through December 2024. The scope of the internal audit will also include the processes and frequency of the Company's automated file matching interactions with the New York State Office of Temporary and Disability Assistance. The purpose of the audit is to ensure accurate enrollment and reporting within the EAP on a going forward basis. By June 30, 2027, the Company will file with the Secretary, both in these proceedings and in Case 14-M-0565, the audit report compiled by the Company's internal audit team. The audit report will be accompanied by a cover letter that: (1) notes the completion of the audit; (2) provides the results of the audit, including a root cause analysis that states and describes any identified errors or issues; and (3) provides the Company's plan and timeline to address any errors or areas of concern identified in the course of the audit.

Should the audit set forth recommendations to address identified errors or issues regarding enrollment records or participant eligibility, the Company will file two additional reports with the Secretary, the first by December 31, 2027, and the second by June 30, 2028, documenting the Company's implementation of the audit recommendations. Furthermore, if the audit identifies errors not previously corrected and filed in Case 14-M-0565 in reported enrollment for the time period contained within the audit scope, the Company will file the relevant and corrected EAP reports in Case 14-M-0565 prior to June 30, 2028, and include a detailed description of the changes and reasons for the changes in the cover letter accompanying the revised filings. Any incremental credits owed to customers that may be the result of EAP enrollment or tiering discrepancies shall be reconciled within the existing EAP deferral mechanism detailed in Appendix F ("Low Income Program - Bill Discount/Energy Affordability Program"). Should the audit identify any customers that received excess credits no adjustment will be made. The audit will not be used to bring any new claims, actions or proceedings regarding the "Settled Matters" as that term is defined in paragraph 6.a. of the settlement agreement adopted by the Commission in its Order Adopting Terms of Settlement Agreement in Case 22-M-0645 issued on June 20, 2024. This does not limit the Commission's ability to take actions unrelated to the "Settled Matters" that could be identified through the audit.

D. EAP Reporting

The Company will begin tracking and recording monthly EAP self-enrollments and include the information in its reporting in Case 14-M-0565.

XII. TARIFF-RELATED MATTERS

A. Generally

Except as may be clarified or altered below, existing tariff provisions and related rate making will generally be continued.

B. Electric Revenue Decoupling Mechanism

The Electric Revenue Decoupling Mechanism ("RDM") will continue to apply to SCs 1, 2, 3, 5, 6, and 8 and those customers taking service under SC 14 whose parent service classification would be either SCs 1, 2, 3 or 6. The RDM will also continue to include SC 13, including those customers taking service under SC 14 whose parent service classification would be SC 13, subject to limitations as described in in the electric tariff. An example is set forth in Appendix R. The RDM is not applicable to SC 9.

The structure and provisions of the electric RDM will continue per the 2024 Rate Plan, with delivery revenue targets established by month for each service classification or sub-classification. The electric bill credits will be included in the reconciliation of target and actual revenue under the Electric RDM.

In the event new RDM delivery revenue targets are not established for the period beginning July 1, 2028, targets have been set forth in Appendix R for purposes of measuring the RDM during Rate Year 4 and will remain in effect until changed by the Commission.

C. Gas RDM

The Gas RDM will continue to be applicable to SCs 1, 2, 6, 12 and 13. The gas RDM will also continue to include SC 11 (transmission, distribution, and distribution large mains), subject to limitations described in the tariff. An example is set forth in Appendix R. The RDM is not applicable to SCs 8, 9, 11 (electric generators), and 14.

The structure and provisions of the Gas RDM will continue per the 2024 Rate Plan, with delivery revenue targets established by month for each service classification. Finally, gas bill credits will be included in the reconciliation of target and actual revenue.

In the event new RDM delivery revenue targets are not established for the period beginning July 1, 2028, targets have been set forth in Appendix R for purposes of measuring the RDM during Rate Year 4 and will remain in effect until changed by the Commission.

D. Electric Factor of Adjustment

The factor of adjustment will be the most recent 36-month system average based on data available at the time of compliance and will continue to be differentiated by service level according to the following service class groups:

(1) SCs 1, 2 Non-Demand, 2 Secondary Demand, 5, 6, 8 and 9;

(2) SCs 2 Primary Demand and 3;

(3) SC 13 Substation; and

(4) SC 13 Transmission.

E. Billing Services Credit

The Company's Billing Services Credit, which is applicable to customers who participate in the Company's Retail Access Program and choose to receive a consolidated bill, is being updated to reflect the Company's most recent cost of service results.

F. Energy Efficiency Credits for Recharge NY

The Company's energy efficiency credit, which is applicable to Recharge NY customers, is being updated consistent with the Company's update to base rates.

G. Reconnection Charges

The Company's Reconnection Charge, which is associated with restoring power for customers whose service has been discontinued for nonpayment, will be updated to: $70 for normal business hours, $260 for normal business hours with a gas mechanic crew, $130 for other hours, and $350 for other hours with a gas mechanic crew.

H. Interruptible Imputation

The interruptible imputation will be set at $2.8 million for each Rate Year, and the structure will continue as set forth in the 2024 Rate Plan.

I. Merchant Function Charge and Lost Revenue

The MFC cost methodology authorized by the Commission in the 2024 Rate Plan will continue.

J. Application for Service

The Company will update the Application for Service section of its gas tariff to provide that, commencing January 1, 2026, the Company shall not be obligated to provide service to an applicant ineligible for gas service pursuant to Energy Law § 11-104 and Executive Law § 378 (as amended by Part RR, Chapter 56 of the Laws of 2023).

K. Incremental Monthly Charge

The Company will change the incremental monthly charge located in the Hourly Pricing Provision of the tariff, including clarifying and streamlining language related to applicability of the incremental monthly charges.

L. Housekeeping Changes

The Company will modify its tariff to make the following clarifying changes: (1) clarify the costs that are included within the Market Price Charge; (2) clarify that incentives related to the active residential managed charging program are recovered via the Miscellaneous II/Non Wire Alternative surcharge; (3) clarify costs included in the Electric Vehicle Make Ready surcharge; and (4) clarify language regarding how the Purchase of Receivables discount is calculated.

M. Conforming Tariffs

The electric and gas tariffs will be amended, as necessary, to conform to the provisions set forth in this JP. Delivery rates for the Excelsior Jobs Program, which follow the marginal cost of service, will be included in the conforming tariffs.

XIII. ECONOMIC DEVELOPMENT

A. Economic Development Programs

The Company's suite of electric economic development programs will continue to include the Manufacturing Building and Infrastructure, Manufacturing Productivity, and Expansion & Retention for Manufacturers Grant Programs. Additionally, the Company will implement the Workforce Clean Energy Program, as further described below.

1. Workforce Clean Energy Program

Beginning in Rate Year 1, the Company will implement a Workforce Clean Energy Program to support workforce development in the clean energy sector. This program will provide grants up to $200,000 to educational institutions (e.g., local community colleges, vocational schools, non-profit organizations, and industry organizations) developing and implementing training and micro-credential programs that focus on developing a skilled workforce ready to meet the demands of the clean energy sector.

In determining the grant amount to be awarded, the Company will consider the following criteria:

- The specific needs and investment levels of the educational institutions applying for the grant, including evaluating costs associated with developing new curricula or programs for workforce training in clean energy fields, such as HVAC, solar, refrigeration, and cooling;

- The extent to which expenses related to expanding or upgrading spaces for hands-on training, as well as expenses related to the purchase of necessary training equipment, are required for the program;
- The extent to which the institution has established partnerships with local industries, community organizations, or other educational institutions to enhance the training program;
- The potential impact on the local workforce, including the number of individuals expected to be trained and the anticipated job creation within the Company's service territory;
- The sustainability and scalability of the institution's proposed program; and
- The availability of supplemental or matching funds from other economic development agencies or partners.

B. Reporting Requirements

The Company shall continue to file an annual report by April 1 of each year that details economic development activity for the prior calendar year. This annual report shall be consistent with the requirements set forth in the Commission's Order Establishing Economic Development Plan Procedures issued in Cases 05-E-0934 et al.[27]

The Company will include a separate chapter in the annual report that discusses the Workforce Clean Energy Program and provides the following information for any grant awarded through the program:

(1) The education/training program that it funded;

(2) How the Company determined the individual grant award amount;

(3) The intended result of the awarded grant;

(5) The number of participants in the education/training program;

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[27] Cases 05-E-0934 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Order Establishing Economic Development Plan Procedures (Aug. 24, 2009).

(6) The method of tracking participant outcomes such that it can provide data to demonstrate whether participants secure employment in the Company's service territory;

(7) The additional economic development assistance the applicant has applied for and received, or will receive in addition to a Workforce Clean Energy Program grant; and

(8) Any feedback received from participants and the facility that hosted the education/training program.

XIV. ENERGY EFFICIENCY PROGRAM AND HEAT PUMP PROGRAM COSTS

The Company will continue to collect the cost of the Company's Energy Efficiency and Heat Pump programs in base rates. For July through December 2025, the base delivery rates in this Proposal reflect Energy Efficiency and Heat Pump program costs authorized by the Commission's Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 issued on January 16, 2020 in Case 18-M-0084.[28] For January through June 2026, and Rate Years 2 and 3, the base delivery rates in this Proposal reflect the proposed budgets put forward by the Company in response to the Commission's July 20, 2023 Order Directing Energy Efficiency and Building Electrification in Case 18-M-0084. The base delivery rates for Rate Year 1 are offset by projected available regulatory liabilities at June 30, 2026.

The Signatory Parties recognize that the Energy Efficiency and Heat Pump program costs are subject to modification pursuant to future Commission orders issued

[28] Case 18-M-0084 - In the Matter of a Comprehensive Energy Efficiency Initiative, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (Jan. 16, 2020). These costs were subsequently amended by the Commission's June 23, 2023 Order Approving Funding for Clean Heat Program, which was specific to Central Hudson.

in Case 18-M-0084. The Company will defer any over/under spending as per Section V.B of this JP, unless the Commission directs otherwise in Case 18-M-0084.

XV. RATE ADJUSTMENT MECHANISM

The Company will implement a Rate Adjustment Mechanism ("RAM") to refund or recover the net balance of RAM Eligible Deferrals and Carrying Charges, positive revenue adjustments ("PRAs"), and unencumbered negative revenue adjustments ("NRAs").[29] All RAM revenues and deferrals are subject to reconciliation. Details regarding RAM eligible deferrals, mechanics, and filing requirements can be found in Appendix H. Illustrative examples of potential bill impacts associated with the RAM are also included in Appendix H.

The listing of balances shown in Appendix H for return to or collection from customers through the RAM during the term of this Proposal is intended to be comprehensive, but the Signatories recognize that future circumstances may create the authorization of new regulatory assets or liabilities. The carrying charges associated with any such new assets or liabilities may be balances eligible for inclusion in the RAM.

XVI. ELECTRIC RELIABILITY

The electric service annual calendar year metrics for System Average Interruption Frequency Index will continue to be 1.30 for the calendar years associated with Rate Years 1 through 3, i.e., 2026, 2027, and 2028, and shall remain in effect thereafter until changed by the Commission in a subsequent Central Hudson rate case. The target for Customer Average Interruption Duration Index will continue to be 2.50 for the calendar years associated with Rate Years 1 through 3, i.e., 2026, 2027, and 2028,

[29] For the avoidance of doubt, incentives associated with EAM achievement will not be collected through the RAM.

and shall remain in effect thereafter until changed by the Commission in a subsequent Central Hudson rate case. The Company will be subject to a 30 basis point NRA for each metric not met. Electric reliability reporting requirements, quarterly meeting requirements, revenue adjustment source, and exclusions are defined in Appendix S.

XVII. GAS SAFETY METRICS

The Signatories agree to the following Gas Safety Metrics beginning in calendar year 2026 as described below and identified in Appendix T. Emergency response performance and damage performance shall adhere to the reporting criteria for the annual Gas Safety Performance Measures report.

A. Emergency Response Time

The gas emergency response time metrics and associated NRAs and PRAs will be as follows:

Emergency Response Time	Percent Completed	(NRA)/PRA (BPs)
30 Minute Response	≥ 95%	6
	≥92% - <95%	4
	≥88% - <92%	2
	≥75% - <88%	0
	< 75%	(12)
45 Minute Response	<90%	(8)
60 Minute Response	<95%	(5)

B. Leak Management

1. Gas Leak Backlog

For purposes of determining the Total Year-End Backlog, which includes Types 1, 2, 2A and 3 leaks as defined in the Commission's regulations,[30] and Year-End Repairable Leaks Backlog, which includes Types 1, 2 and 2A leaks, "Year-End" is

[30] See 16 NYCRR §§ 255.811, 255.813, 255.815, and 255.817.

defined as any time during the last 10 days of the calendar year.

Starting in calendar year 2026, the Company will be subject to the following leak backlog management targets and associated revenue adjustments (gas, pre-tax):

Gas Leak Backlog	**# of Leaks**	**(NRA)/PRA (BPs)**
Total Year-End Backlog	≥ 56	(15)
	≥ 50 - ≤ 55	(6)
	≥ 30 - ≤ 49	0
	≥ 15 - ≤ 29	2
	≥ 6 - ≤ 14	4
	≤ 5	6

The Company is only eligible to earn the PRA associated with Total Year-End Backlog if its Year-End Repairable Backlog (Type 1, 2 and 2A) is six (6) or less. Only "successful elimination" of a leak in accordance with 16 NYCRR Part 255.819 will be considered a valid leak repair. A leak is considered to have been successfully eliminated when the Company either has performed multiple inspections (two or more) to confirm that zero-percent gas-in-air readings have been maintained, or a re-check has been completed per the Commission's regulations. Types 1, 2 and 2A leaks that fail a re-check as required by 16 NYCRR 255.819 must be added back to the Total Year-End Back Log and the Year-End Repairable Leaks Backlog.

For any Type 3 leak repaired during the months of November and December, the Company will be required to conduct a re-check within 14 to 30 days after repair to confirm no gas-in-air readings before such repair will be considered a valid repair for purposes of PRA eligibility. However, Type 3 leaks that were repaired in November or December but are not re-checked or that fail a re-check will be excluded from the Total Year-End Backlog for purposes of determining an NRA.

C. Damage Prevention

The Company will be subject to the following damage prevention targets and associated NRAs and PRAs:

Total Damage Rate	(NRA) (BPs)	Maximum NRA BPs/Year	PRA (BPs)	Maximum PRA BPs/Year
<0.95	N/A		6	
≥0.95. - <100.	N/A		4	
≥1.00 - <1.05	N/A		2	6
≥1.05 - <1.45	0	(20)	N/A	
≥1.45 - <1.55	(5)		N/A	
≥1.55 - <1.70	(10)		N/A	
≥1.70	(20)		N/A	

For rate case established targets, the Total Damage Rate will include the hand excavation damages with a one call ticket. Hand excavation damages without a ticket will be excluded from the Total Damage Rate.

D. Gas Safety Violations Performance Measure

Central Hudson will incur an NRA for each instance of noncompliance (occurrence or violation) with the High Risk and Other Risk pipeline safety-related regulations set forth in Appendix U, as identified in Staff's field and record audit letters. The regulations identified in Appendix U are drawn from 16 NYCRR Parts 255 and 261 and Title 49 of the United States Code of Federal Regulations (49 CFR) Part 193. The Gas Safety Violations Performance Measure set forth in this Proposal covers the calendar years associated with Rate Years 1 through 3, i.e., 2026, 2027, and 2028, and shall remain in effect thereafter until changed by the Commission in a subsequent Central Hudson rate case. The provisions governing the Gas Safety Violations Performance Measure are included in Appendix U.

E. Leak Prone Pipe

In calendar years 2025, 2026 and 2027, the Company will replace or eliminate, at a minimum, 15 miles of leak prone pipe per year and will incur an NRA of 15 basis points if the mileage achieved in any year is less than 15 miles. In calendar year 2028, the Company will replace or eliminate its remaining current inventory of leak prone pipe (approximately seven miles) and will incur an NRA of two basis points per mile remaining as of December 31, 2028. For the avoidance of doubt, not all pipe sections will be replaced in strict adherence to their risk ranking established by the Company's main segment risk model. The Company expressly retains the right to prioritize projects based on factors other than risk. The Company will remove or retire leak prone services in conjunction with leak prone pipe removal efforts. Central Hudson will seek alternatives to the replacement of pipelines scheduled to be eliminated by eliminating double runs of pipe or pursuing Non-Pipes Alternatives ("NPAs") with a positive benefit cost analysis.

F. Leak Prone Services

The Company will continue its Leak Prone Service Replacement Program[31] that focuses on services that are considered leak prone pipe but are not included within the leak prone pipe replacement program. Commencing in calendar year 2025, the Company is eligible to earn a PRA of four basis points if it removes 211 or more leak prone services per year.

[31] For purposes of this program, a leak prone service is a service containing leak-prone materials, such as wrought iron or bare steel, that is connected to a protected main.

G. Community Emergency Response Drill Program

The Signatory Parties agree that the Company will continue its Community Gas Emergency Response Drill ("CGERD") Program, which provides simulated full-scale gas emergency exercises in the community to test and enhance communication protocols and logistics of all first responder organizations within a community. Participants may include entities such as gas operators, fire departments, police departments, emergency medical services, county emergency management personnel, employees of the facility being used for the exercise, and municipal officials. The CGERD Program's objective is to conduct municipality-wide gas emergency drills for the purpose of evaluating the coordinated response of Company and municipal agencies to gas events. The Company shall earn a PRA of four basis points for each drill conducted with municipalities and first responders as part of the CGERD Program with a limit of two drills per year.

1. Reporting Requirements

Prior to the date of each event, the Company shall submit to the Secretary a list of the entities invited to the emergency drill, along with the schedule of activities. Within 30 days of completing the emergency drill, the Company shall submit to the Secretary a report on the emergency drill including the attendance list, a detailed summary of the activities completed during the event, and the cost of the event.

H. Gas Safety Total PRA / NRA Basis Points Allocation Per Year

Safety Metrics	(NRA) BPs	PRA BPs
Leak Management	(15)	6
Leak Prone Pipe	(15)	0
Emergency Response Time	(25)	6
Damage Prevention	(20)	6
Gas Safety Violations	(75)	0
Total Basis Points	**(150)**	**18**

Other Gas Safety Initiatives/Programs	(NRA) BPs	PRA BPs
Leak Prone Services Replacement Program	0	4
Conduct Municipal-Wide Gas Emergency Drills (4 basis points per occurrence for up to two times per year)	0	8
Total Basis Points	**0**	**12**

	(NRA) BPs	PRA BPs
Total Basis Points	**(150)**	**30**

I. Continuation

All Gas Safety Metrics effective in calendar year 2028 shall remain in effect on an annual basis for the target levels identified until modified by the Commission.

XVIII. <u>CUSTOMER SERVICE</u>

A. Customer Service Performance Indicators

The Customer Service Performance Indicators ("CSPIs") and associated reporting requirements will consist of the following measures: (1) PSC Complaint Rate; (2) Residential Customer Satisfaction Survey; and (3) Percent of Call Answered by a Representative within 30 Seconds.

All CSPI targets and potential PRAs and NRAs shall remain in effect until modified by a Commission order. All metrics are measured on a calendar-year basis starting in 2026. The CSPIs described below are summarized in Appendix V and associated reporting requirements described in Appendix M.

1. PSC Complaint Rate

The metric targets for the PSC Complaint Rate and corresponding NRAs are:

PSC Complaint Rate	(NRA) BPs
≤ 1.0	None
> 1.0	(5)
≥ 1.1	(10)
≥ 1.2	(15)

The PSC Complaint Rate is the annual average monthly rate of escalated PSC Complaints received by Staff of the Office of Consumer Services ("OCS") divided by the customer total per 100,000 customers, as calculated by Staff. The PSC Complaint Rate is reported by OCS Staff at a one-tenth digit of accuracy.

2. Residential Customer Satisfaction Survey

The metric targets for the Residential Customer Satisfaction Survey and corresponding NRAs are:

CSI Satisfaction Index	(NRA) BPs
≥ 89.0%	None
< 89.0%	(5)
≤ 87.1%	(10)
≤ 85.3%	(15)

The Residential Customer Satisfaction Survey Index results are based on customer responses to eight questions within the Company's "How Did We Do Survey," which is sent to a random selection of customers (in English and Spanish) that recently interacted with the Company. Customers may select "Strongly Agree/Very Satisfied," "Agree/Satisfied," "Disagree/Dissatisfied," "Strongly Disagree/Very Dissatisfied," and "Not Applicable." The Customer Satisfaction Survey Index is a weighted measure and is calculated by taking the annual percent of "Strongly Agree/Very Satisfied" and "Agree/Satisfied" responses for each question and applying a 50% weight to question 1 and applying a 50% weight to the average of questions two through eight. The metric is calculated and reported at the nearest one-tenth of a percent.

3. Percent of Calls Answered by a Representative Within 30 Seconds

The Percent of Calls Answered by a Representative within 30 Seconds is the percentage of calls answered by a Company representative within 30 seconds of the customer's request to speak to a representative between the hours of 8:00 AM and 4:30 PM Monday through Friday (excluding holidays). The performance rate is the sum of the system-wide number of calls answered by a representative within 30 seconds divided by the sum of the system-wide number of calls where a customer requests to speak with a representative, minus all calls abandoned within 30 seconds.

The Percent of Calls Answered by a Representative within 30 Seconds targets and corresponding NRAs are:

Call Answer Rate	2026 (NRA) BPs	2027 (NRA) BPs	2028 (NRA) BPs
≥ 67.0%	None	None	None
< 67.0%	(4)	(5)	(5)
≤ 61.4%	(8)	(10)	(10)
≤ 55.8%	(12)	(13)	(15)

4. Appointments Kept

The Company will continue to provide a bill credit of $20 to customers for each scheduled appointment missed by the Company.

5. Residential Service Terminations/Uncollectibles Incentive Mechanism

The Signatory Parties agree to continue the pause of this mechanism through the term of this Proposal.

6. Events Outside of the Company's Control

Factors beyond the Company's control could adversely affect its ability to meet the CSPI targets established herein. Examples of such factors, depending on the totality of circumstance presented, could include, but are not limited to pandemics/epidemics or natural disasters. Accordingly, the Company does not waive and expressly retains its right to petition the Commission for a waiver, release, or other relief related to its inability to meet the targets set forth herein.

B. Call Center Legislation Reporting

As discussed in Section V.B., the Company is authorized to defer incremental costs incurred to comply with Chapter 107 of the Laws of 2025. The Company will file quarterly reports with the Secretary in these rate proceedings within 60 days following the end of each calendar quarter. The reports shall include the following information, broken down by month:

(1) Call Center Customer Service Representative ("CSR") staffing levels;

(2) Status of hiring;

(3) CSR training activity;

(4) Overall spending broken out by labor, external call center costs, training, equipment, and office space; and

(5) Additional expenses outside of the categories identified in item (4), which will each be accompanied by an explanation and justification.

C. Language Access

In 2025, the Company will provide customer bills and forms in Spanish and continue translation of its website into Spanish.

With respect to Limited English Proficient ("LEP") populations in the Company's service territory, the Company agrees to continue to monitor, track and analyze these populations on an annual basis, utilizing readily available census data only. This will include coding Customer Information System accounts of non-Spanish speaking LEP customers, solely for the purpose of monitoring LEP populations in the Company's service territory.

Within 90 days of the effective date of an order setting rates in these proceedings, the Company will implement inclusion of a messaging block of the top five languages other than English and Spanish so that LEP customers are included in all steps of the collections process. The messaging will indicate to the customer that the document they are reading is important and should be translated and will include the Company's 1-800 number.

Further, the Company will develop an implementation plan to code previously uncoded residential customer accounts as LEP when a customer self-identifies during the collections process and provide a 15-day extension during which the Company will not pursue service termination. This 15-day window could be at any time in the overall collections process regardless of the type of collections notification (e.g., Reminder Notice, Final Termination Notice, outbound phone call, etc.) that has been issued on the customer's account. The Company's implementation plan will include any currently unidentified technical or project constraints and will be filed within these proceedings prior to the end of Rate Year 1. The plan will include a go-live prior to the end of Rate Year 2, recognizing that the Secretary can extend all deadlines in this Proposal or in the Commission's order setting rates in these proceedings. Once live, the Company will track and report on this program on an annual basis and file such reports with the Secretary in these rate proceedings.

D. Short-Term Payment Agreements

The Company will develop an implementation plan by the end of Rate Year 1 to waive finance charges for customers with short-term payment agreements, without adjustment to the revenue requirement presented in this Proposal. The implementation plan will include a deadline for go-live of these changes prior to the end of Rate Year 2, recognizing that the Secretary can extend all deadlines in this Proposal or in the Commission's order setting rates in these proceedings. Additionally, the implementation plan will include a narrative of any currently unidentified technical or project constraints.

E. Voluntary Protections During Extreme Weather

The Company will continue the following cold weather protections and heat provisions. Notwithstanding the foregoing, should the Commission establish extreme weather protections/requirements applicable to Central Hudson as part of Case 24-M-0586, such protections/requirements will supersede the protections/requirements of this section.

1. <u>Cold Weather Protections</u>

The Company will continue additional winter protections for residential customers during the cold weather period of November 1 through April 15 ("Cold Weather Period"). These protections include:

(1) Central Hudson will accept all HEAP payments and provide the customer with continued service regardless of the amount due and/or the customer's payment status.

(2) Central Hudson will offer a new minimum Deferred Payment Agreement upon receipt of an emergency HEAP grant. For regular HEAP grants, if a customer has a defaulted agreement, the regular grant will be applied toward reinstating that agreement and the Company will request that the difference be paid by the customer. If the customer cannot pay, the Company will suggest that they turn to the Department of Social Services for an emergency HEAP grant. Central Hudson will take a fair and reasonable approach to reinstating these defaulted agreements.

(3) Central Hudson will refrain from scheduling residential service terminations on days when the local weather forecast predicts a high temperature below-freezing (32 degrees) temperatures on any given day, or predicts “feels like” temperatures for the entire day at or below-freezing (32 degrees) for two or more consecutive days.

(4) Central Hudson will refrain from locking customers who are coded as Elderly, Blind or Disabled.

(5) Central Hudson will assist Low-Income and Elderly, Blind and Disabled customers. To ensure the safety of these customers during the Cold Weather Period, Central Hudson will not terminate the gas service of these customers due to non-payment. Also, if these customers may be eligible for disconnection due to non-payment, the Company will continue to provide electric service to allow these customers to sustain their heating source. However, for the first and last month of the Cold Weather Period (i.e., November 1 through November 30 and March 16 through April 15), Central Hudson may terminate non-heat related electric service due to non-payment for these customers unless weather conditions defined in item (3) above exist at the time.

2. <u>Extreme Heat Protections</u>

The Company will suspend electric residential service terminations for non-payment of service if: (1) the heat index is forecasted by the National Weather Service to reach 93 degrees or higher, including on the calendar day before, in the Company’s service territory; or (2) the actual heat index reaches 93 degrees or higher on any given day.

XIX. OUTREACH AND EDUCATION

The Company will, during the term of this JP, continue to file an annual Outreach and Education Plan with the Secretary by April 1 of each Rate Year in Case 17-M-0475 using the template set forth in Appendix W.

XX. OTHER PROGRAMS AND INITIATIVES

A. Residential Methane Detector Program

The Signatory Parties agree that the Company will continue its Residential Methane Detector Program, which will be funded through the Company's gas O&M expenses.

B. First Responder Training Program

The Signatory Parties agree that the Company will continue its First Responder Training Program, which will be funded through the Company's gas O&M expenses.

C. Pipeline Safety Management System

The Pipeline Safety Management System ("PSMS") is a management tool used by pipeline operators to manage various aspects of pipeline safety and create a safety framework to identify and mitigate threat and risks and ultimately to improve safety. The Signatory Parties agree that the Company's costs associated with its PSMS will also be funded through the Company's gas O&M expense.

XXI. EARNINGS ADJUSTMENT MECHANISMS

Under the JP, the Company will have five EAMs and four scorecard metrics. The Company's five EAMs, all of which apply to the Company's electric operations, are: (1) Distributed Energy Resource ("DER") Utilization – Photovoltaic; (2) DER Utilization – Battery Energy Storage Systems; (3) Electric Load Management; (4) Residential Managed Charging; and (5) EV Adoption. The Company's four scorecard metrics include three electric operations metrics (Load Factor, Residential Energy Intensity, and Commercial Energy Intensity) and one gas operations metric (Gas Peak Reduction). These EAMs and scorecard metrics are described in detail in Appendix X.

A. EAM Reporting Requirements

Central Hudson will file annual EAM reports with the Secretary no later than June 1 of each year in these proceedings, setting forth the Company's performance relative to each EAM metric target, savings and benefits achieved, and calculations for incentives earned, including proration of any incentives related to metric achievement between performance levels (as applicable).

B. Recovery of EAM Incentives

Incentives associated with EAMs will be recovered through the existing Miscellaneous Charges EAM Factor, which is a component of the Company's energy cost adjustment mechanism ("ECAM"). Recovery will be over a 12-month period commencing with the first billing batch of September. Recovery will be on a kWh basis for non-demand customers and on a kW basis for demand customers, with rates determined for each service classification or sub-classification based on the aggregate results of the following allocation methodologies divided by either forecast kWh or kW over the respective recovery period:

- Load Management and Residential Managed Charging EAMs: Allocated using the transmission demand allocator;
- EV Adoption EAM: Allocated using the energy allocator; and
- DER Utilization EAMs: Allocated using three allocators which will be equally weighted – coincident peak, non-coincident peak, and energy allocator.

These rates will be applied to the energy (kWh) or demand (kW) deliveries, as applicable, on the bills of all customers served under SCs 1, 2, 3, 5, 6, 8, 9, 13, and 14.

Customers taking service under SC 14 will be billed the rate applicable to their Parent Service Classification, which is the Service Classification that the customer would otherwise qualify for based on the customer's usage characteristics.

Recoveries (eleven months actual, one month forecast) will be reconciled to allocable costs for each 12-month recovery period ending August 31st, with any over- or under-recoveries included in the development of succeeding Miscellaneous Charges EAM Factors. Reconciliation amounts related to the one-month forecast will be included in the next subsequent rates determination.

For billing purposes, recovery for non-demand customers will be included in the Miscellaneous Charges, with the combined amount shown as one line item on customer bills. Cost recovery for demand customers will be through the Miscellaneous Charges II, a separate line item on customer bills.

XXII. CLIMATE AND ENERGY LEADERSHIP INITIATIVES

The Signatory Parties agree that this Proposal contains provisions supportive of and in furtherance of the objectives of the CLCPA, including:

- Continuation of CLCPA Phase 1 projects;
- Replacement of leak prone pipe, year-end leak backlog targets, and continuation of the Leak Prone Services Replacement Program;
- Continuation of the Company's differentiated gas pilot program;
- Continuation of the Company's fleet electrification efforts;
- Elimination of gas declining block rates;
- Elimination of the high-volume usage rate discount offer to firm non-residential gas transportation customers;

- Continuation of the Company's efforts to explore NPAs designed to displace the need for traditional gas infrastructure investments; and
- The incorporation of Clean Heat Program information into the Company's natural gas service applications.

XXIII. GAS RELIABILITY AND SUPPLY ISSUES

A. PA Consulting Incremental Expense

The Company's deferral of costs associated with PA Consulting's services regarding the Company's Gas System Long-Term Plan in Case 23-G-0676 shall not include the difference between the actual final billed professional fees of PA Consulting (not to exceed $578,652) and the professional fees set in the original contract ($470,000). The Company may defer PA Consulting's billed expenses, which are limited to $35,250.

B. Differentiated Gas

Differentiated gas is natural gas that has been documented as having been extracted and handled in a manner that reduces emissions intensity compared to traditional gas exploration and production processes. The Company will continue its pilot program to procure differentiated gas,[32] limited to an annual cost above traditional supplies of $200,000 per year, during the term of this Proposal. Costs associated with the procured differentiated gas will be recovered similarly to other natural gas purchases through the Gas Supply Charge.

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[32] As part of the 2024 Rate Plan, the Commission approved the Company's proposal to procure responsibly-sourced gas up to a cost above traditional supplies of $200,000 during the Rate Year that was the subject of the 2024 Rate Plan. "Differentiated gas" and "responsibly-sourced gas" refer to the same product.

The Company agrees that any purchases of differentiated gas will be limited to those that meet the highest certification standards, which include: (1) MiQ Grade A rating; (2) Oil and Gas Methane Partnership 2.0 Level 5 rating; or (3) Project Canary Trustwell Platinum rating.

The Company will continue to file monthly reports with the Secretary to the Commission in Case 24-G-0462, providing details of its purchases of differentiated gas, including the name of the certifier, the volume of differentiated gas purchased, and the methane intensity of differentiated gas and the cost per unit, along with the steps the Company undertakes when purchasing differentiated gas.

C. Non-Pipes Alternatives Outreach

For the Transmission Service Replacements and Leak Prone Service Replacements NPA programs and each individual NPA associated with an Area of Pressure Concern Identified in System Modeling set forth below, Central Hudson will submit an implementation plan with the Secretary (to be made available on DMM in Cases 24-E-0461 and 24-G-0462) that includes, at a minimum, measurement and verification procedure(s), the solutions to be included, a demonstration of whether the costs of each NPA are incremental to the Company's revenue requirement or will be displacing a project subject to the Net Plant Reconciliation mechanism(s), a benefit cost analysis, and a customer and community outreach plan. For Transmission Service Replacements and Leak Prone Service Replacements, Central Hudson will file implementation plans no later than January 31, 2026. Central Hudson will file updates to each implementation plan with the Secretary (to be made available on DMM in Cases 24-E-0461 and 24-G-0462) on an annual basis by December 1 of each year. The updates will address any changes to the components of the implementation plan and any additional plans for the upcoming year.

The Company will continue to provide outreach materials regarding energy efficiency, air source heat pumps, and geothermal heat pumps to customers on a regular basis within each rate year and continue to provide outreach materials on these programs on its public facing website. Additionally, the Company will focus outreach efforts for NPAs in the following areas:

(1) Areas of Pressure Concerns Identified in System Modeling: This comprehensive strategy shall include targeted outreach efforts and initiatives to increase customer adoption of a combination of energy efficiency measures, heating electrification, or demand response programs within areas of pressure concern. Examples of these areas are illustrated in the Company's Gas System Long-Term Plan filed on November 20, 2024, in Case 23-G-0676. For each NPA within an area of pressure concern, Central Hudson will submit a unique implementation plan following the development of a solution or solicitation of vendors through an RFP process. This implementation plan would include a customer and community outreach plan that provides eligible customers within the non-pipe alternative area with sufficient time to make an informed decision and adopt any necessary equipment conversions prior to the date in which the traditional gas infrastructure solution is expected to commence.

(2) Transmission Service Replacements: The Company will provide outreach materials for its Clean Heat Program to customers impacted by

Transmission Service Replacements and will evaluate Transmission Service Replacements for inclusion within the Company's NPA Program. For projects commencing on or after January 1, 2026, customers eligible to participate in a NPA due to a transmission service replacement will receive applicable outreach materials to make an informed decision and for a contractor to make any necessary appliance conversions at least six months in advance of the date the traditional gas infrastructure solution is expected to commence.

(3) Leak Prone Service Replacements: For projects commencing on or after January 1, 2026, the Company will provide outreach materials for its Clean Heat Program to customers impacted by the Leak Prone Service Replacement Program at least six months in advance of the date the traditional gas infrastructure solution is expected to commence. The Company will continue to evaluate Leak Prone Service replacements as an NPA Program and will file any updates to its implementation plan on an annual basis by December 1 of each year.

Additionally, for applicants located within 100 feet of a gas main, the Company will provide outreach materials for its Clean Heat Program to gas applicants within 100 feet of a gas main as they inquire or apply for service as described in Section XXIII.D below.

D. Natural Gas Service Agreement

The Company will modify its online and PDF Natural Gas Service Agreement forms to include information on the Company's Clean Heat Program. Specifically, the first page of the online form will be modified to include a link to a one-page informational sheet detailing Clean Heat Program alternatives. A rich text field will also be integrated into the top of the first page of the application materials, which will provide a substantive overview of Clean Heat Program alternatives and a link to the Central Hudson Heat Pump page. The PDF form will be modified to include a one-page Clean Heat Program informational sheet.

In addition, a rich text field will be added to the top of the Company's Contact Us webpage, calling out Clean Heat Program alternatives, and providing a link to the Central Hudson Heat Pump page.

XXIV. <u>GAS CAPACITY RELEASE</u>

A. Pipeline Capacity for Sales and Transportation Customers

The rate at which capacity is released for the Company's gas retail program will be set equal to the corresponding rate for pipeline capacity included in the Gas Supply Charge assessed to full service customers commencing with the month following the effective date of the conforming tariffs filed in these proceedings. In order to provide notification of the capacity release rate to ESCOs pursuant to the Company's Calendar of Gas Transportation Scheduling, the Company will revise its methodology for calculation of the weighted average cost of capacity rate applicable to the gas Retail Access Program within the first month following the corresponding tariff changes to allow for the change to take effect the first of the following month.

B. Collaborative Process

Prior to the end of 2026, Central Hudson will initiate a collaborative process with interested parties to evaluate the capacity available for release under the Company's gas Retail Access Program. As the first step in this process and in advance of the first meeting, Central Hudson will provide an analysis that identifies any potential differences between supply pipelines that are released to retail access marketers for SC 6, 12 and 13 customers participating in the Company's Retail Access Program versus supply pipelines that are used by Central Hudson on behalf of firm sales customers. The analysis will include actual transportation costs and average market supply costs for the 36 months ending March 2026 by month. This analysis will also include a summary for discussion among the participants in the collaborative of the advantages and disadvantages of the current allocation methodology on behalf of retail access customers and firm sales customers. Working with the collaborative, the Company will file a report before the end of Rate Year 2 summarizing its conclusions and attaching additional comments, if any, by participants of the collaborative, including any resulting changes to the Company's Gas Transportation Operating Procedures Manual ("GTOP"). The GTOP revisions will be filed at least 90 days in advance of the effective date of any program changes.

XXV. MISCELLANEOUS PROVISIONS

A. Continuation of Provisions; Rate Changes; Reservation of Authority

Unless otherwise expressly provided herein, the provisions of this Proposal will continue after Rate Year 3 for electric and for gas, unless and until superseding rates and/or terms adopted by Commission order become effective. For any provision subject to Rate Year 1, Rate Year 2 and Rate Year 3 targets, respectively, the Rate Year 3 target shall be applicable to any additional Rate Year(s).

Nothing herein precludes Central Hudson from filing a new general rate case for rates to be effective on or after July 1, 2028. Except pursuant to rate changes permitted by this section, the Company will not file rates to become effective prior to July 1, 2028.

Changes to the Company's base delivery service rates during the term of this Rate Plan will not be permitted, except for the changes provided for or detailed in this Proposal, and, subject to Commission approval, changes as a result of the following circumstances.

(1) A minor change, whose revenue effect is *de minimis* or essentially offset by associated changes within the same class, or other classes such that the difference in the revenues that the Company's base delivery service rates are designed to produce overall before such a change is *de minimis*, may be made to any individual base delivery service rate or rates. It is understood that, over time, such minor changes may be necessary and that they may continue to be sought during the term of this Rate Plan.

(2) Upon the occurrence, at any time, of circumstances that, in the judgment of the Commission, threaten the Company's economic viability or ability to maintain safe, reliable and adequate service so as to warrant an exception to the limitations on rate changes provided for or detailed in this Proposal, Central Hudson will be permitted to file for an increase in base delivery service rates.

(3) The Signatories recognize that the Commission reserves the authority to act on the level of the Company's rates in the event of unforeseen circumstances that, in the Commission's opinion, have such a substantial impact on the range of earnings levels or equity costs envisioned by this Proposal so as to render the Company's rates unjust, unreasonable, or insufficient for the provision of safe and adequate service.

(4) Nothing herein will preclude any Signatory Party from petitioning the Commission for approval of new services, the implementation of new service

classifications and/or cancellation of existing service classifications, or rate design or revenue allocation changes relating to such petition that are not contrary to the agreed upon terms and conditions set forth herein. All such changes will be implemented on a revenue neutral and earnings neutral basis.

(5) The Signatory Parties reserve the right to take any position regarding any filings made under this section.

B. Request for Exemption from Disclosure

Nothing in this Proposal prevents the Company from seeking a request for exemption from disclosure under 16 NYCRR Part 6 for all or any part(s) of any document or report filed with the Commission (or submitted to Staff) in accordance with this Proposal or prohibits or restricts any other party from challenging any such request.

C. Dispute Resolution

In the event of any disagreement over the interpretation of this JP or the implementation of any of the provisions of this JP that cannot be resolved informally among the parties, such disagreement will be resolved as follows. The parties promptly will confer and, in good faith, will attempt to resolve such disagreement. If any such disagreement cannot be resolved by the parties, then the parties may mutually submit a request to the Chief ALJ that an ALJ be designated to resolve the dispute on an expedited basis using alternative dispute resolution techniques or such other procedures as the ALJ decides are appropriate under the circumstances, including but not limited to the issuance of a written determination. Within 15 days from the ALJ's determination, any party may petition the Commission for relief from the ALJ's determination on the disputed matter.

D. Provisions Not Separable

The Signatories intend this Proposal to be a complete resolution of all the issues in Cases 24-E-0461 and 24-G-0462.[33] The terms of this Proposal are submitted as an integrated whole. If the Commission does not accept this Proposal according to its terms as the basis of the resolution of all issues addressed without change or condition, each Signatory shall have the right to withdraw from this Proposal upon written notice to the Commission within ten (10) days of the Commission's issuance of an Order setting rates in these proceedings. Upon such a withdrawal, that Signatory shall be free to pursue its respective positions in these proceedings without prejudice, and this Proposal shall not be used in evidence or cited against any such Signatory or used for any other purpose. It is also understood that each provision of this Proposal is in consideration and support of all the other provisions and expressly conditioned upon acceptance by the Commission of all Proposal provisions. Except as set forth herein, none of the Signatories is deemed to have approved, agreed to, or consented to any principle, methodology or interpretation of law underlying or intended to underlie any provision herein.

E. Provisions Not Precedent

The terms and provisions of this Proposal apply solely to, and are binding only in, the context of the purposes and results of this Proposal. None of the terms or provisions of this Proposal, nor any methodology or principle utilized herein, and none of the positions taken herein by any Signatory Party may be referred to, cited, or relied upon by any other Signatory Party in any fashion as precedent or otherwise in any other

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[33] The Signatories have agreed to a process to address further actions to be taken in the future to fully effectuate this Proposal. See Section XXV.H ("Further Assurances").

proceeding before this Commission or any other regulatory agency or before any court of law for any purpose other than furtherance of the purposes, results, and disposition of matters governed by this Proposal and except as may be necessary in explaining derivation of specific costs or accounting treatments as relevant to future ratemaking proceedings. Concessions made by Signatories on various issues included in the JP do not preclude those parties from addressing such issues in future rate proceedings or in other proceedings. This Proposal shall not be construed, interpreted or otherwise deemed in any respect to constitute an admission by any Signatory regarding any allegation, contention, or issue that arose in these proceedings or is addressed in this Proposal.

F. Submission of Proposal

Each Signatory Party agrees to submit this Proposal to the Commission, to support and request its adoption by the Commission, and not to take a position in these proceedings contrary to the agreements set forth herein or to assist another participant in taking such a contrary position in these proceedings. The Signatories believe that the resolution of the issues, as set forth in the Proposal, is just and reasonable and otherwise in accordance with the PSL, the Commission's regulations and applicable Commission policies and decisions. The Signatories believe that the Proposal will satisfy the requirements of PSL § 65(1) that Central Hudson provide safe and adequate service at just and reasonable rates.

G. Effect of Commission Adoption of Terms of this Proposal

No provision of this Proposal or the Commission's adoption of the terms of this Proposal shall in any way abrogate or limit the Commission's statutory authority under the PSL. The Signatories recognize that any Commission adoption of the terms of this

Proposal does not waive the Commission's ongoing rights and responsibilities to enforce its orders and effectuate the goals expressed therein, nor the rights and responsibilities of Staff to conduct investigations or take other actions in furtherance of its duties and responsibilities.

H. Further Assurances

The Signatories recognize that certain provisions of this Proposal require that actions be taken in the future to fully effectuate this Proposal. Accordingly, the Signatories agree to cooperate with each other in good faith in taking such actions.

I. Extension

Nothing in this Proposal will be construed as precluding the Signatories and other interested parties from convening in the future and from reaching agreement to extend the term of the Rate Plan set forth in this Proposal on mutually acceptable terms and from presenting an agreement concerning such extension to the Commission for its approval.

J. Scope of Provisions

No term or provision of this Proposal that relates specifically to either electric or gas service limits any rights of the Company or any party to petition the Commission for any purpose with respect to the service(s) not specified in such term or provision.

K. Execution

This Proposal may be executed in one or more counterparts, all of which taken together shall constitute one and the same instrument which shall be binding upon each Signatory Party when its executed counterpart is filed with the Secretary to the Commission. This JP will be binding on each and every Signatory when the counterparts have been executed. In the event that any signature is delivered by facsimile transmission or by e-mail delivery of a PDF format data file, such signature shall create a valid and binding obligation of the party executing (or on whose behalf such signature is executed) with the same force and effect as if such facsimile or PDF signature page were an original thereof.

L. Entire Agreement

This Proposal, including all attachments, exhibits and appendices, if any, represents the entire agreement of the Signatories with respect to the matters resolved herein.

IN WITNESS WHEREOF, the Signatories hereto have affixed their signatures below as evidence of their agreement to be bound by the provisions of this Proposal.

WHEREFORE, this JP in Cases 24-E-0461 and 24-G-0462 has been agreed to as of the 13th day of May, 2025, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

____

Joseph J. Hally
Vice President, Regulatory Affairs
Central Hudson Gas & Electric Corporation

WHEREFORE, this JP in Cases 24-E-0461 and 24-G-0462 has been agreed to as of the 13th day of May, 2025, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Brandon F. Goodrich
Staff Counsel
New York State Department of Public Service

WHEREFORE, this JP in Cases 24-E-0461 and 24-G-0462 has been agreed to as of the 12 day of May, 2025, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

S. Jay Goodman

S. Jay Goodman, Esq.
Partner, Couch White LLP
Counsel to Multiple Intervenors

WHEREFORE, this JP in Cases 24-E-0461 and 24-G-0462 has been agreed to as of the 13th day of May, 2025, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Steven Wing-Kern Lee
Senior Attorney, Spilman Thomas & Battle, PLLC
Counsel to Walmart

Appendix A, Schedule 1

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Income Statements
($000)

	Rate Years Ending		
	6/30/26	6/30/27	6/30/28
Operating Revenues			
Delivery Revenues - Before Increase	539,339	597,244	644,581
Rate Increase	46,407	30,678	21,698
Revenue Taxes	11,855	13,154	14,360
Legacy Hydro Revenue	4,400	4,400	4,400
Other Operating Revenues	15,026	15,247	15,564
Total Operating Revenues	617,027	660,724	700,602
Operating Expenses			
Labor	95,507	98,850	102,309
Executive Incentive Compensation	-	1,100	1,145
Management Variable Pay	6,711	6,979	7,258
Employee Benefits	17,337	18,008	18,707
Pension Plan	(20,351)	(19,328)	(18,192)
Other Post Employee Benefits	(7,625)	(7,403)	(6,912)
Employee Training, Safety & Education	2,239	2,288	2,338
Production Maintenance	105	82	85
Right of Way Maintenance - Transmission	4,038	4,205	4,388
Right of Way Maintenance - Distribution	26,300	26,300	26,300
Stray Voltage Testing	894	914	934
System Engineering & Compliance	124	127	130
Substation Testing & Maintenance	459	469	479
Transmission Repairs & Maintenance	642	656	670
Distribution Repairs & Maintenance	9,843	10,945	11,797
Transformer Installations & Removals	(645)	(659)	(673)
Informational & Institutional Advertising	179	183	187
Meter Installations, Removals & Maintenance	(1,230)	(1,257)	(1,285)
Research and Development	4,292	4,386	4,482
Economic Development	193	400	400
Meter Reading, Collections & Call Volume Overflow	6,980	6,859	6,761
Bill Print & Postage	2,521	2,576	2,633
Payment by Credit/Debit Card	1,400	1,400	1,400
Low Income Program	11,039	11,039	11,039
Uncollectible Accounts & Collection Agency Fees	10,414	11,139	11,778
Regulatory Commission General Assessment	2,630	2,893	3,182
Environmental SIR Costs	-	-	3,010
Environmental All Other	224	229	234
Information Technology	18,273	19,861	21,632
Telephone	2,372	2,424	2,477
Rental Agreements	2,327	2,378	2,430
Security of Infrastructure	4,180	4,463	4,766
Maintenance of Buildings & Grounds	2,847	2,910	2,974
Major Storm Reserve	12,443	12,443	12,443
Major Storm Amortization	5,991	5,991	5,991
Non Major Storm Restoration	7,535	7,701	7,870
Material & Supplies	3,064	3,131	3,200
Stores Clearing to Expense	204	208	213
Transportation - Depreciation	3,300	3,557	3,824
Transportation - Fuel	1,098	1,122	1,147
Transportation - All Other	1,589	1,624	1,660
Rate Case Expenses	1,240	1,240	664
Legal Services	1,653	1,689	1,726
Consulting & Professional Services	3,190	3,260	3,332
Miscellaneous General Expenses	5,970	6,143	6,361
Injuries and Damages	6,054	6,706	7,442
Other Operating Insurance	1,421	1,599	1,804
Office Supplies	1,044	1,067	1,090
Management & Operational Audit Costs	150	150	150
Energy Efficiency	11,117	12,515	13,037
Heat Pump Programs	11,771	13,205	13,752
Amortization of EE/Heat Pump Assets	1,875	1,875	1,875
Expenses Allocated to Affiliates	(1)	(1)	(1)
Miscellaneous Charges	1,259	1,287	1,315
Amortization of Unprotected Asset (TCJA)	1,998	1,998	1,998
Productivity Imputation	(1,264)	(1,321)	(1,367)
Amortization of Depreciation Reserve Adjustment	864	864	864
Total Operating Expenses	287,784	303,469	319,253
Other Deductions			
Property Taxes	45,390	50,309	54,775
Revenue Taxes	11,855	13,154	14,360
Payroll Taxes	6,825	7,064	7,311
Other Taxes	3,930	4,197	4,459
Depreciation	87,497	95,755	103,430
Total Other Deductions	155,497	170,479	184,335
State Income Taxes	9,922	9,587	9,170
Federal Income Taxes	23,573	24,926	27,236
Total Income Taxes	33,496	34,513	36,406
Total Operating Revenue Deductions	476,777	508,461	539,993
Operating Income	$140,250	$152,263	$160,609
Rate Base	$2,010,683	$2,148,066	$2,242,919
Rate of Return	6.97%	7.09%	7.16%

Appendix A, Schedule 2

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Gas Income Statements
($000)

	Rate Years Ending		
	6/30/26	6/30/27	6/30/28
Operating Revenues			
Delivery Revenues - Before Increase	164,486	182,481	195,447
Rate Increase	18,966	13,887	16,908
Revenue Taxes	4,634	5,151	5,766
Dansammer Revenue	1,000	1,000	1,000
Interruptible Imputation	2,800	2,800	2,800
Other Operating Revenues	1,723	1,860	1,950
Total Operating Revenues	193,609	207,179	223,872
Operating Expenses			
Labor	28,435	29,430	30,460
Executive Incentive Compensation	-	275	286
Management Variable Pay	1,678	1,745	1,815
Employee Benefits	4,900	5,092	5,292
Pension Plan	(5,787)	(5,496)	(5,173)
Other Post Employee Benefits (OPEB)	(2,168)	(2,105)	(1,965)
Employee Training, Safety & Education	972	993	1,015
System Engineering & Compliance	177	179	182
T&D Repairs & Maintenance	4,013	4,101	4,191
Pipeline Integrity & Inspection	2,775	2,836	2,898
Gas Leak Repairs - Distribution Main	737	679	618
Meter Installations, Removals & Maintenance	(373)	(381)	(389)
Research and Development	911	931	951
Informational & Institutional Advertising	85	87	89
Meter Reading, Collections & Call Volume Overflov	1,745	1,715	1,691
Bill Print & Postage	634	648	662
Payment by Credit/Debit Card	440	440	440
Low Income Program	3,446	3,446	3,446
Uncollectible Accounts & Collection Agency Fees	3,773	4,035	4,360
Regulatory Commission General Assessment	779	857	943
Environmental SIR Costs	-	-	3,253
Environmental All Other	54	55	57
Information Technology	4,270	4,660	5,096
Telephone	625	639	653
Rental Agreements	540	552	564
Security of Infrastructure	1,046	1,117	1,192
Maintenance of Buildings & Grounds	680	695	710
Material & Supplies	907	928	948
Stores Clearing to Expense	62	63	65
Transportation - Depreciation	836	896	957
Transportation - Fuel	386	394	403
Transportation - All Other	625	639	653
Rate Case Expenses	306	306	166
Legal Services	678	693	708
Consulting & Professional Services	677	633	661
Miscellaneous General Expenses	1,527	1,570	1,625
Injuries and Damages	1,582	1,747	1,933
Other Operating Insurance	356	400	452
Office Supplies	284	290	296
Management & Operational Audit Costs	38	38	38
Energy Efficiency	1,726	1,374	1,341
Expenses Allocated to Affiliates	-	-	-
Miscellaneous Charges	936	957	978
Amortization of Unprotected Asset (TCJA)	376	376	376
Productivity Imputation	(370)	(386)	(400)
Amortization of Depreciation Reserve Adjustment	57	57	57
Total Operating Expenses	65,376	68,200	74,594
Other Deductions			
Property Taxes	22,731	23,761	25,475
Revenue Taxes	4,634	5,151	5,766
Payroll Taxes	1,940	2,008	2,078
Other Taxes	442	456	469
Depreciation	30,831	33,862	36,811
Total Other Deductions	60,578	65,238	70,599
State Income Taxes	3,519	3,585	3,557
Federal Income Taxes	8,258	9,223	10,031
Total Income Taxes	11,777	12,808	13,588
Total Operating Revenue Deductions	137,731	146,246	158,781
Operating Income	$55,878	$60,933	$65,090
Rate Base	$801,154	$859,581	$908,861
Rate of Return	6.97%	7.09%	7.16%

Appendix A, Schedule 3

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Rate Base
($000)

	Rate Years Ending		
	6/30/26	6/30/27	6/30/28
Book Cost of Utility Plant	$2,633,367	$2,820,253	$2,995,671
Less: Accumulated Provision for Depreciation and Amortization	(698,249)	(741,579)	(808,741)
Net Plant	1,935,118	2,078,674	2,186,930
Noninterest-Bearing Construction Work in Progress	54,846	62,707	64,121
Customer Advances for Undergrounding	(3,387)	(3,387)	(3,387)
Deferred Charges	63,966	72,688	83,296
Accumulated Deferred Federal Taxes	(195,402)	(214,951)	(236,110)
Accumulated Deferred State Taxes	(44,793)	(51,526)	(59,446)
Working Capital	87,692	91,218	94,872
Unadjusted Rate Base	1,898,040	2,035,423	2,130,276
Capitalization Adjustment to Rate Base	112,643	112,643	112,643
Total	$2,010,683	$2,148,066	$2,242,919

Appendix A, Schedule 4

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Gas Rate Base
($000)

	Rate Years Ending		
	6/30/26	6/30/27	6/30/28
Book Cost of Utility Plant	$1,097,411	$1,191,039	$1,278,054
Less: Accumulated Provision for Depreciation and Amortization	(245,431)	(271,084)	(299,805)
Net Plant	851,980	919,955	978,249
Noninterest-Bearing Construction Work in Progress	22,791	20,778	18,656
Customer Advances for Undergrounding	(1,008)	(1,008)	(1,008)
Deferred Charges	(11,948)	(6,950)	(1,213)
Accumulated Deferred Federal Taxes	(104,015)	(114,145)	(124,637)
Accumulated Deferred State Taxes	(27,462)	(30,765)	(34,284)
Working Capital	24,575	25,475	26,857
Unadjusted Rate Base	754,913	813,340	862,620
Capitalization Adjustment to Rate Base	46,241	46,241	46,241
Total	$801,154	$859,581	$908,861

Appendix B Sheet 1 of 2

Central Hudson Gas & Electric Corporation

Cases 24-E-0461 & 24-G-0462

Illustrative Example of Make Whole Provision - Electric

	Jul-25			Current Rates					Proposed Rates					Unrealized
	Custs/Faces	kWh	kW	Cust. Chg.	kWh	MFC kWh	Bill Credit	kW	Cust. Chg.	kWh	MFC kWh	Bill Credit	kW	Revenue
SC 1 Residential	279,936	212,386,497		$ 21.50	$ 0.12777	$ 0.00293	$ -		$ 22.50	$ 0.13860	$ 0.00424	$ (0.00487)		$ 1,823,986
SC 2 Non Demand	34,136	15,828,328		$ 32.50	$ 0.10135	$ 0.00429	$ -		$ 33.50	$ 0.11176	$ 0.00602	$ (0.00514)		$ 144,934
SC 2 Secondary	11,945	131,836,397	399,519	$ 140.00	$ 0.00467	$ 0.00021	$ -	$ 14.78	$ 160.00	$ 0.00467	$ 0.00031	$ (0.00219)	$ 16.00	$ 450,775
SC 2 Primary	149	20,084,898	52,848	$ 530.00	$ 0.00144	$ 0.00002	$ -	$ 10.71	$ 570.00	$ 0.00144	$ 0.00003	$ (0.00097)	$ 11.70	$ 38,998
SC 3 Primary	37	31,210,952	68,580	$ 2,600.00			$ -	$ 13.56	$ 2,750.00			$ (0.45000)	$ 14.82	$ 61,100
SC 5 Area Lighting **	3,840	760,000		$ 228,220.00		$ 0.00762	$ -		$ 247,510.00		$ 0.01203	$ (0.00901)		$ 12,442
SC 6 Residential TOU 12 Hour on pk^^	1,400	640,500		$ 24.50	$ 0.16291	$ 0.00221	$ -		$ 25.50	$ 0.17851	$ 0.00221	$ (0.00346)		$ 9,176
SC 6 Residential TOU 12 Hour off pk^^		1,189,500			$ 0.05430	$ 0.00221	$ -			$ 0.05950	$ 0.00221	$ (0.00346)		$ 6,185
SC 6 Residential TOU 5 Hour on pk				$ 24.50	$ 0.13508	$ 0.00221	$ -		$ 25.50	$ 0.14732	$ 0.00221	$ (0.00346)		
SC 6 Residential TOU 5 Hour off pk					$ 0.11681	$ 0.00221	$ -			$ 0.12739	$ 0.00221	$ (0.00346)		
SC 8 Street Lighting **	212	710,000		$477,850		$ 0.00050	$ -		$506,240		$ 0.00070	$ (0.01182)		$ 19,998
SC 9 Traffic Signals	59	60,000		$ 4.97		$ 0.00210	$ -		$ 5.26		$ 0.00296	$ (0.00694)		$ (348)
SC 13 Substation	6	9,530,000	16,136	$ 8,500.00			$ -	$ 10.96	$ 9,700.00			$ (0.55000)	$ 12.26	$ 19,302
SC 13 Transmission	6	58,910,000	93,952	$ 13,500.00			$ -	$ 6.57	$ 15,500.00			$ (0.37000)	$ 7.69	$ 82,464
Total														**$ 2,669,013**

^^ Actual make whole calculation will reflect customers and kWh billed at 5-hr rate and 12-hr rate, as applicable.

** Total fixture revenue included in Cust. Chg. Column.

Month of July 2025 shown for illustrative purposes. Actual time period covered by make whole may extend beyond illustrative time period shown here.

Appendix B Sheet 2 of 2
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Illustrative Example of Make Whole Provision - Gas

	Jul-25			Current Rates					Proposed Rates					Unrealized
	Customers	Mcf	MDQ	Cust. Chg.	Ccf	MFC Ccf	Bill Credit	MDQ	Cust. Chg.	Ccf	MFC Ccf	Bill Credit	MDQ	Revenue
SC 1/ 12 Residential														
Block 1	76,591	13,497		$ 26.25			$ -		$ 27.25			$ (0.04889)		$ 76,591
Block 2		25,988			$ 1.49150					$ 1.54670				$ 14,345
Block 3		20,583			$ 1.26540					$ 1.54670				$ 57,900
MFC						$ 0.01706					$ 0.01766			$ 360
Gas Bill Credit														$ (29,367)
SC 2/6/13 Non-Residential														
Block 1	12,720	2,512		$ 41.00			$ -		$ 43.00			$ (0.02092)		$ 25,440
Block 2		48,882			$ 0.69570					$ 0.75310				$ 28,058
Block 3		105,753			$ 0.68400					$ 0.75310				$ 73,075
Block 4		22,510			$ 0.64520					$ 0.75310				$ 24,288
High Volume		53,105			$ 0.58340					$ 0.75310				$ 90,119
MFC						$ 0.01699					$ 0.01760			$ 1,420
Gas Bill Credit														$ (48,694)
SC 11 DLM														
Customer Charge - First 1,000 ccf	1			$ 7,100.00			$ -		$ 5,600.00			$ (0.00574)		
Block 1		100			$ 0.03470					$ 0.04400				$ (1,500)
Block 2		22,312												$ 2,066
MDQ			4,900					$ 18.09					$ 20.62	$ 12,397
Gas Bill Credit														$ (1,172)
SC 11 D														
Customer Charge - First 1,000 ccf	5			$ 2,400.00			$ -		$ 2,200.00			$ (0.00889)		
Block 1		400			$ 0.05000					$ 0.06000				$ (1,000)
Block 2		37,610												$ 3,721
MDQ			6,164					$ 26.01					$ 29.50	$ 21,512
Gas Bill Credit														$ (2,668)
SC 11 T														
Customer Charge - First 1,000 ccf	2			$ 4,000.00			$ -		$ 2,700.00			$ (0.00369)		
Block 1		200			$ 0.02310					$ 0.02800				$ (2,600)
Block 2		75,720												$ 3,700
MDQ			8,548					$ 11.06					$ 12.57	$ 12,907
Gas Bill Credit														$ (2,801)
SC 11 EG														
Customer Charge	1			$ 3,000.00					$ 2,700.00					$ (300)
MDQ			5,000					$ 18.09					$ 20.38	$ 11,450
Total														**$ 369,250**

Month of July 2025 shown for illustrative purposes. Actual time period covered by make whole may extend beyond illustrative time period shown here.

Appendix C, Schedule 1

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Net Plant Targets
($000)

	Electric[1]			
	RY1	RY2	RY3	
Electric Net Plant Targets[2]:				
Plant In Service	2,633,367	2,820,253	2,995,671	
Accumulated Reserve [3]	(698,249)	(741,579)	(808,741)	
Net Plant	1,935,118	2,078,674	2,186,930	
NIBCWIP	54,846	62,707	64,121	
Adjustment for Solar on Company Facilities[6]	(191)	(990)	(1,558)	
Net Electric Plant Targets	1,989,773	2,140,391	2,249,493	5
Depreciation Expense Targets:				
Transportation Depreciation [4]	3,300	3,557	3,824	
Depreciation Expense [4]	87,497	95,755	103,430	
Adjustment for Solar on Company Facilities[6]	(8)	(24)	(37)	
Electric Depreciation Expense Target	90,789	99,288	107,217	5

	Gas[1]			
	RY1	RY2	RY3	
Gas Net Plant Targets[2]:				
Plant In Service	1,097,411	1,191,039	1,278,054	
Accumulated Reserve [3]	(245,431)	(271,084)	(299,805)	
Net Plant	851,980	919,955	978,249	
NIBCWIP	22,791	20,778	18,656	
Adjustment for Solar on Company Facilities[6]	(48)	(247)	(390)	
Net Gas Plant Targets	874,723	940,486	996,515	5
Depreciation Expense Targets:				
Transportation Depreciation [4]	836	896	957	
Depreciation Expense [4]	30,831	33,862	36,811	
Adjustment for Solar on Company Facilities[6]	(2)	(6)	(9)	
Gas Depreciation Expense Target	31,665	34,752	37,759	5

[1] - Electric and Gas amounts include allocation of Common Plant.

[2] - Electric and Gas Plant, Reserves and NIBCWIP are from the respective Rate Base amounts shown on Appendix A, Schedules 3 and 4.

[3] - Includes Retirement Work-in-Progress.

[4] - Electric and Gas Depreciation are from the respective Income Statement amounts shown on Appendix A, Schedules 1 and 2.

[5] - Net Plant and Depreciation Targets.

[6] - Adjustment to Net Plant and Depreciation Targets to reflect removal of Solar on Company facilities. Refer to Section V.A.2.

Appendix C, Schedule 2

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Example Calculation of Revenue Requirements on Net Plant Targets
($000)

	Electric[1]			Gas[1]		
	RY1	RY2	RY3	RY1	RY2	RY3
Targets[2]:						
Net Plant & NIBCWIP	1,989,773	2,140,391	2,249,493	874,723	940,486	996,515
Depreciation Expense	90,789	99,288	107,217	31,665	34,752	37,759
Actual (For Illustrative Purposes Only):						
Total Net Plant & NIBCWIP	1,991,000	2,143,500	2,250,000	870,000	940,000	1,004,000
Depreciation Expense	91,500	100,000	107,500	30,500	35,000	37,500
Difference (For Illustrative Purposes Only):						
Total Net Plant & NIBCWIP	1,227	3,109	507	(4,723)	(486)	7,485
Depreciation Expense	711	712	283	(1,165)	248	(259)
Determination of Revenue Requirements:						
Return Component:						
Net Plant & NIBCWIP Difference	1,227	3,109	507	(4,723)	(486)	7,485
x Pre-tax WACC	8.59%	8.70%	8.77%	8.59%	8.70%	8.77%
Return Component	105	271	44	(406)	(42)	657
Revenue Requirement on Differences:						
Depreciation	711	712	283	(1,165)	248	(259)
Return Component	105	271	44	(406)	(42)	657
Total	816	983	327	(1,571)	206	398
Cumulative Revenue Requirement Impact	816	1,799	2,126	(1,571)	(1,365)	(967)
Amount Deferred for Customer Benefit - Smaller of Cumulative Amount at End of RY3 or $0[3]			-			(967)

[1] - Electric and Gas amounts include allocation of Common Plant

[2] - See Appendix B

[3] - Negative amounts indicate Regulatory Liabilities due to Customers.

Appendix D
Schedule 1 of 3
Central Hudson Gas & Electric Corporation
Case 24-E-0461 and Case 24-G-0462

The annual reports called for in item V.A.5 of this Proposal will be comprised of the two spreadsheets in this Appendix, appropriately filled out by the Company to reflect actual and forecasted events for the preceding calendar year.

Major Capital Project Report (Work Orders over $1,000,000)

			Project Expenditures ($,000)											Project In-Service Date		
Work Order #	Project Description*	Investment Category	Current Approved Work Order Estimate	Actuals thru 12/31/2025	2021 and Prior Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026	Future Years	Total	%Total to Current Estimate	Current Approved Estimate	Projected or Actual	Notes
	ELECTRIC PRODUCTION															
	ELECTRIC TRANSMISSION															
	ELECTRIC SUBSTATION															
	ELECTRIC NEW BUSINESS															
	ELECTRIC DISTRIBUTION															
	ELECTRIC TRANSFORMERS															
	ELECTRIC METERS															
	ELECTRIC STORMS															
	GAS TRANSMISSION															
	GAS REGULATOR STATIONS															
	GAS DISTRIBUTION IMPROVEMENT															
	LAND AND BUILDINGS															
	SOFTWARE, I.T. EQUIPMENT & SECURITY															
	COMMUNICATION - NETWORK STRATEGY															
		TOTAL	0	0	0	0	0	0	0	0	0	0	0%			

*CLCPA Phase 1 projects and programs will be included regardless of total cost threshold

Appendix D
Schedule 2 of 3
Central Hudson Gas & Electric Corporation
Case 24-E-0461 and Case 24-G-0462

Program/Project		2025			2026			2027			2028			2025-2028 Total		
		Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Budget
PRODUCTION																
GT PROJECTS	1-1131-00-18															
HYDRO MINOR PROJECTS	1-1121-00-06 x project name															
	1-1121-00-13 x project name															
	1-1121-00-12 x project name															
	1-1121-00-17 x project name															
	1-1121-00-18 x project name															
HYDRO PROJECTS	1-1122-00-18															
HYRDO SCADA UPGRADE																
	Production Subtotal															
TRANSMISSION																
2017 ROW DEFICIENCY PROJECT	1-1232-00-17															
C LINE REBUILD	1-1212-04-15															
CAT 12 - SMART WIRES INTERCONNECT.	10141															
CAT 12 - SOLAR INTERCONNECT. (CIAC)	10140															
CL LINE REBUILD	1-1212-07-16															
EF LINE REBUILD	1-1212-08-16															
G LINE 69KV REBUILD	1-1212-06-13															
H-LINE PECKHAM QUARRY EASEMENT	1-1232-70-18															
HF LINE REBUILD	1-1212-04-18															
HG LINE RELOCATION	1-1212-12-16															
HG LINE: NEW 69KV LINE	1-1212-02-19															
HIGH PRIORITY REPLACEMENTS	1-1221-80-14 x project name															
	1-1221-90-17 x project name															
	1-1221-90-18 x project name															
HIGHLAND SUB TO HURLEY AVE SUB	1-1212-11-16															
HK LINE	1-1212-54-15															
HK, MK REROUTE FOR KERHONSKSON SUB	1-1212-54-13															
HONK FALLS SUBSTATION TIE-IN	1-1212-01-19															
HR/DR BULKHEAD	1-1212-01-18															
HS LINE RAIL TRAIL RE-ROUTE	1-1212-02-17															
KM/TV REBUILD PROJECTS	1-1212-15-16															
KNAPPS CORNERS SUBSTATION REBUILD	1-1212-06-16															
NERC ALERT (UNTIL JUNE 2016) AND HP	1-1221-90-16															
NERC ALERT/HPR	1-1221-90-15															
NETWORK STRATEGY	1-1212-14-16															
NETWORK STRATEGY	1-1212-14-17															
NEW 115KV LINE 12.25MI-ART V11 -H L	1-1232-70-05															
NEW 115KV LINE-KGN/SAUG-NEAR SB LIN	1-1232-67-05															
O LINE DASHVILLE TAP SWITCH	1-1212-03-18															
OR,P,O,N REROUTE FOR STURGEON POOL	1-1212-55-12															
ROUTE 84 115KV FT LINE RELOCATION	1-1212-01-17															
ROW MINOR PROJECTS	1-1231-00-12															
ROW REPAIR PROJECT (DEFICIENCIES)	1-1232-00-18															
SAG MITIGATION	1-1221-90-13															
STORM HARDENING (ER, HR, DR)	1-1212-04-16															
TR LINE RE-ROUTE / RETIREMENT	1-1212-05-17															
TRANSMISSION MINOR PROJECTS	1-1211-00-15 x project name															
	1-1211-00-16 x project name															
	1-1211-00-17 x project name															
	1-1211-00-18 x project name															
WH 1 & 2 REBUILD	1-1212-13-16															
WH1&2 REBUILD	1-1212-05-13															
1-121L-00-05	1-121L-00-05															
A LINE REBUILD	1-1212-03-15															
CAT 12 - SUBSTATION REROUTE	10180															
HG LINE 69KV REBUILD (HONK FALLS -	10261															
Q LINE 69KV REBUILD (PLEASANT VALLE	10260															
DR LINE TRANSITION STATION	1-1212-06-15															
ER LINE TRANSITION SORM HARDENING	1-1212-05-15															
CAT 12 FK LINE 115KV UPGRADE (K-HF)	10401															
CAT 12 MG AND GK LINE 115KV UPGRADE	10480															
CAT 12 SK LINE REBUILD - 115KV	10400															
P LINE 115KV UPGRADE (HF-SP)	10402															
115KV 5 LINE REBUILD	10562															
115KV NC LINE REBUILD	10561															
ELECTRIC TRANSMISSION COATING	10564															
FK LINE RELOCATION-ACCORD SUB REM.	1-1212-03-17															
69kV GM Line: Retirement of Clinton Avenue Tap Section																
	Transmission Subtotal															
SUBSTATION																
345KV SWITCH REPLACEMENT PROGRAM	1-1312-01-17															
BETHLEHEM RD. RD LINE & TR RELAYING	1-1312-14-18															
BOARDMAN ROAD SUBSTATION RETIREMENT	1-1312-12-18															
BOULEVARD DRIVEWAY EXPANSION	1-1312-10-18															
BOULEVARD REPLACE TRANFORMER #1	1-1312-45-15															
BREAKER REPLACE PRGM 115KV-13.8KV-B	1-1312-85-11															
BREAKER REPLACEMENT PROGRAM (115KV	1-1312-92-17															
COLDENHAM REPL J & CW LINE RELAYS	1-1312-44-12															
CONVERSE ST. EMERGENCY XFMR REPL.	1-1312-29-18															
COXSACKIE MODERNIZATION	1-1312-19-18															
DANSKAMMER DISC SWITCH REPLACEMENT	1-1312-21-15															
DANSKAMMER SUBSTATION STORM HARDENI	1-1312-21-14															
DW LINE BLOCKING CARRIER REPL.	1-1312-09-17															
E. FISHKILL GIC MONITOR ON TR #1	1-1312-26-17															
E. WALDEN 115 KV DW LINE COM UP	1-1312-11-17															
EAST DELAWARE TUNNEL OUTLET	1-1312-01-12															
EAST WALDEN CW LINE RELAY REPL	1-1312-56-12															
FISHKILL PLAINS LTC CONTROLS REPL.	1-1312-30-16															
FISHKILL PLAINS NF LINE RELAY REPL.	1-1312-37-18															
FORGEBROOK LCB II RELAY REPL	1-1312-31-18															
FORGEBROOK NEW CKT TO BEACON	1-1312-05-15															
FORGEBROOK REPLACE (11) 14.4KV ROLL	1-1312-18-15															
FOUR CORNERS MICROGRID	1-1312-08-18															
FREEHOLD BAT ALRM/LTC TAP POSITION	1-1312-33-18															
HIBERNIA SUBSTATION NEW DIST CKT	1-1312-25-15															
HIGH FALLS MODERNIZATION	1-1312-46-17															
HIGH FALLS RETAINING WALL	1-1312-10-17															
HONK FALLS GM-737 & HG-709 BKR REPL	1-1312-45-17															
HONK FALLS HG LINE RELAYING UPGRADE	1-1312-19-15															
HURLEY AVE 115 KV MODERNIZATION	1-1312-53-16															
HURLEY AVE LINE TERMINAL WORK	1-1312-23-16															
HURLEY AVE SERIES COMP CAP BANK	1-1312-12-11															
HURLEY AVE. 69KV BKR EMERGENCY REPL	1-1312-30-18															
HURLEY AVE. SDU (SMART WIRES)	1-1312-17-18															
HURLEY AVENUE 345KV PHASE ANGLE REG	1-1312-12-15															
HURLEY AVENUE 69KV/15KV MODERNIZATI	1-1312-28-15															
INWOOD AVE RELAY MODERNIZATION	1-1312-25-17															
JANSEN AVE. REPLACE RTU	1-1312-35-18															
LAWRENCEVILLE 'CL' LINE RE-CONFIG.	1-1312-27-18															

Appendix D
Schedule 2 of 3
Central Hudson Gas & Electric Corporation
Case 24-E-0461 and Case 24-G-0462

Program/Project		2025			2026			2027			2028			2025-2028 Total		
		Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Budget
LINCOLN PARK LTC CONTROL PANEL REPL	1-1312-19-16															
LINCOLN PARK LTC CONTROLS UPGRADE	1-1312-16-18															
MANCHESTER SUBSTATION MODERNIZATION	1-1312-43-13															
MAYBROOK LTC REPLACEMENT	1-1312-33-16															
MODENA ADD 115KV BREAKER (RING BUS)	1-1312-52-17															
MONTGOMERY STREET TRANSFORMER REPLA	1-1312-20-14															
MONTGOMERY SUBSTATION REBUILD	1-1312-53-17															
MYERS CORNERS SUBSTATION	1-1312-11-18															
N. CATSKILL XFMR REPL. & UPGRADE	1-1312-13-18															
N. CHELSEA 'NF' LINE RELAY REPL.	1-1312-36-18															
N. CHELSEA AC & DC LINE RELAYING	1-1312-23-17															
N. CHELSEA LCB II RELAY REPL	1-1312-32-18															
N. CHELSEA PUMP STATION NYCBWS	1-1312-21-17															
NEVERSINK CKT. 3091 VIPER STATUS	1-1312-24-18															
NEW 115/69 KV SS AUTO TRANSFORMER	1-1312-14-16															
NEW KNAPPS CORNERS SUBSTATION	1-1312-50-13															
NEW STURGEON POOL 115KV SUBSTATION	1-1312-16-12															
NORTH CHELSEA LTC CONTROL PANEL REP	1-1312-50-16															
NORTH CHELSEA TRANSFORMER REPLACEME	1-1312-09-16															
PLEASANT VALLEY ARRESTER REPL.	1-1312-40-18															
REPAIR FAULTED 6094 CKT. EXIT	1-1312-38-18															
REYNOLDS HILL PS CABLE	1-1312-40-17															
REYNOLDS HILL SUB, REPLACE TRANSF.	1-1312-27-15															
ROCK TAVERN 115 KV RJ LINE MOD.	1-1312-54-16															
ROCK TAVERN 115KV BKR REPLACEMENTS	1-1312-23-18															
ROCK TAVERN 115KV W-681 BKR REPL.	1-1312-22-18															
ROCK TAVERN REPL J LINE RELAYS	1-1312-55-12															
ROSETON '305' LINE A2 PROTECTION UP	1-1312-16-13															
ROSETON 30592 MOTOR MECH REPL.	1-1312-49-16															
ROSETON 345KV DISC. SWITCH REPL.	1-1312-47-17															
S. CAIRO RTU REPLACEMENT	1-1312-35-16															
SAND DOCK TR. 4 LTC & 6011 METER	1-1312-18-18															
SHENANDOAH SUBSTATION FIREWALL	1-1312-47-13															
SOLAR PROJECTS	1-1312-28-17 x project name															
	1-1312-28-18 x project name															
SOUTH CAIRO SUB MODERNIZATION	1-1312-48-17															
SPACKENKILL DTT TO DCA SOLAR SITE	1-1312-56-16															
SUBSTATION BATTERY REPLACEMENT PROG	1-1312-05-18															
SUBSTATION BATTERY REPLACEMENTS	1-1312-44-16															
SUBSTATION D-SUSTAINING PROJECTS	1-1312-99-19															
SUBSTATION MINOR PROJECTS	1-1311-00-17 x project name															
	1-1311-00-18 x project name															
SUBSTATION T-SUSTAINING PROJECTS	1-1312-98-19															
SUGARLOAF "SL" LINE RELAY REPL.	1-1312-08-17															
TINKERTOWN G LINE FIBER INSTALL	1-1312-04-18															
TINKERTOWN G-LINE SECTIONALIZING	1-1312-15-18															
TODD HILL ADD 69KV G LINE	1-1312-23-14															
TRAP ROCK SUBSTATION	1-1312-52-16															
UNDER FREQUENCY LOAD SHED-COMPLIANC	1-1311-00-11															
UNION AVENUE REPLACE SWTCHGR #1, 2	1-1312-32-15															
WEST BALMVILLE SUB MODERNIZATION	1-1312-29-16															
WEST BALMVILLE TERMINAL UPGRADE	1-1312-09-12															
WICCOPPEE RTU REPLACEMENT	1-1312-34-16															
WOODSTOCK RTU REPLACEMENT	1-1312-16-17															
WOODSTOCK SUBSTATION REPLACE SWITCH	1-1312-31-15															
ROCK TAVERN 'RD' LINE RELAY REPL.	1-1312-20-18															
MODENA REPLACE HMI COMPUTERS	1-1312-38-14															
MYERS CORNERS SUBSTATION UPGRADE	1-1312-30-14															
FROST VALLEY ASCO CONTROLLER REPL	1-1312-20-17															
SUBSTATION - MINOR SPECIFIC	1-1311-00-08															
Tilcon																
	Substation Subtotal															
NEW BUSINESS																
ELEC. & GAS COMB. URD - BLANKET	1-142L-02-08															
ELEC. N.B. OVERHEAD - BLANKET	1-141L-01-08															
ELEC. URD - MINOR MID-HUDSON	1-1431-05-06															
ELEC. URD - MINOR MID-HUDSON	1-1431-05-07															
ELEC. URD - BLANKET	1-143L-03-08															
NEW BUSINESS	1-1412-00-11 x project name															
	1-1412-00-12 x project name															
	1-1412-00-13 x project name															
	1-1412-00-14 x project name															
	1-1412-00-15 x project name															
	1-1412-00-16 x project name															
	1-1412-00-17 x project name															
	1-1412-00-18 x project name															
ELEC. URD - MINOR NEWBURGH	1-1431-08-07															
INS GAS SERV. 3/4 REG.6 250CCF MTR.	1-143L-03-06															
	New Business Subtotal															
DISTRIBUTION IMPROVEMENTS																
280A ELECTRONIC RECLOSER PROGRAM	1-1570-01-15															
4800V CONVER/INFRASTRUCTURE PRG	1-1551-12-18															
801/802/803/881/882 BEACON PH 4/4	1-1551-23-18															
CATV MAKE-READY	1-1551-01-17 x project name															
	1-1551-01-18 x project name															
CE MESH / PROTECTOR RELAYS	1-1551-15-17 x project name															
	1-1551-15-15 x project name															
CEMI/WORST CIRCUIT RELIABILITY PRG	1-1551-18-18															
COPPER WIRE REPLACEMENT PRG	1-1551-11-18															
DA - ALT PROGRAM 17	1-1570-02-17															
DA - MAJOR PROGRAM	1-1551-19-18															
DASHVILLE/STURGEON POOL CIRCUIT EXI	1-1560-01-16															
DI (1551-0X) - OPERATING/INFRASTR	1-1551-03-18															
DI (1551-0X) - RELIABILITY	1-1551-10-18															
DI (1551-0X) - THERMAL/VOLTAGE	1-1551-02-18															
DI BLANKETS (15BL-01)	1-151L-01-08															
DI CONVERSIONS (1521-0X)	1-1521-00-18															
DI MINORS (1511-0X)	1-1511-00-18															
DIST POLE REPLACEMENT PROGRAM	1-1551-08-17															
DISTIBUTION AUTOMATION - MAJOR PROG	1-1570-01-16															
DISTR IMPR (1551-0X) - RELIABILITY	1-1551-02-17 x project name															
	1-1551-02-14 x project name															

Appendix D
Schedule 2 of 3
Central Hudson Gas & Electric Corporation
Case 24-E-0461 and Case 24-G-0462

Program/Project		2025			2026			2027			2028			2025-2028 Total		
		Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Annual Budget	Actual	JP Budget	Board Approved Budget
DISTRI IMPR (1551-0X) - OPER/ INFRA	1-1551-03-17															
DISTRIBUTED GENERATION INTERCONNECT	1-1551-23-17															
DISTRIBUTION IMPROV RELIABILITY	1-1551-02-11															
DISTRIBUTION IMPROVEMENT (1551-0X)	1-1551-01-16 x project name															
	1-1551-01-15 x project name															
	1-1551-02-16 x project name															
	1-1551-03-13 x project name															
	1-1551-03-15 x project name															
	1-1551-03-16 x project name															
DISTRIBUTION IMPROVEMENT CONVERSION	1-1521-00-15 x project name															
	1-1521-00-16 x project name															
DISTRIBUTION POLE REPL PRG - 18	1-1551-08-18															
ELEC. DIST IMP. MINOR - CATSKILL	1-1511-01-06															
ELECTRONIC RECLOSER REPL PROGRAM	1-1570-01-17															
EMERGENT	1-1551-26-18															
LECTRIC - DISTRIBUTION IMPROV. BLAN	1-1512-03-89 x project name															
	1-1552-01-06 x project name															
MONTGOMERY SUBSTATION CIRCUIT EXITS	1-1551-21-18															
NETWORK CABLE AND EQUIPMENT	1-1551-15-18															
OVERHEAD SECONDARY REPL PROGRAM	1-1551-04-19															
POUGHKEEPSIE 14.4 KV STUDY	1-1551-04-13 x project name															
	1-1551-04-11 x project name															
	1-1551-04-14 x project name															
RD/BRIDGE REBD/RELO PRJ 1531-0X	1-1531-00-18															
RELOCATION BLANKETS (15BL-02)	1-152L-02-08															
ROAD REBLD RELO PROJECTS (1531-OX)	1-1531-00-17															
SECONDARY NETWORK UPGRADE PROGRAM (	1-1551-14-18 x project name															
	1-1551-14-16 x project name															
SOLAR PROJECTS	1-1551-25-18															
STANFORDVILLE INTEGRATION	1-1551-24-19															
UNION AVE INTEGRATION	1-1551-22-18															
URD REPLACEMENT	1-1551-16-18															
CAT 15 - SUB CIRCUIT EXITS	10181															
OVERHEAD SECONDARY REPLACEMENT PROG	1-1551-05-15															
RECLOSER REPLACEMENT PROGRAM	1-1551-09-15															
CAT 15 STORM HARDENING PROGRAM	10403															
DISTRIBUTION AUTOMATION - ALT PROGR	1-1570-02-14															
CAT 15 - 5KV AERIAL CABLE	10440															
CAT 15 DA OTHER	10461															
CAT 15 RESILIENCY PROGRAM	10404															
DISTRIBUTION AUTOMATION SYSTEM & IN	1-1570-01-13															
CAT 15 SECONDARY NETWORK UPGRADE	10462															
DISTRIBUTION POLE REPL PROGRAM	1-1551-08-14															
STORM CAPITAL	10524															
	Distribution Improvements Subtotal															
TRANSFORMERS																
CAPACITORS	1-1621-00-08															
DISTRIBUTION TRANSFORMERS	1-1611-00-07 x project name															
	1-1611-00-08 x project name															
LINE REGULATORS	1-1631-00-08															
NETWORK PROTECTORS	1-1641-00-08															
	Transformers Subtotal															
METERS																
ELECTRIC METERS	1-1731-00-08 x project name															
	1-1731-00-06 x project name															
METERING INSTRUMENT TRANSFORMERS	1-1721-00-08 x project name															
	1-1721-00-09 x project name															
SPECIAL ELECTRIC METER INSTALLATION	1-1711-00-08															
	Meters Subtotal															
STORM																
	1-191L-01-08															
	Storm Subtotal															
Total Electric																

Appendix D
Schedule 3 of 3
Central Hudson Gas & Electric Corporation
Case 24-E-0461 and Case 24-G-0462

Program/Project		Q4 2024 December YTD					2024	Schedule		Explanation
		Actual	JP Approved Budget	Board Approved Annual Budget	$ Variance	% Variance	Total Budget	Estimated In Service Date	Projected or Actual In-Service Date	Major Variation Explanations (Variations +/- 10% and $500K)
ELECTRIC										
PRODUCTION										
GT PROJECTS	1-1131-00-18									
HYDRO MINOR PROJECTS	1-1121-00-18									
HYDRO PROJECTS	1-1122-00-18									
	Production Subtotal									
TRANSMISSION										
2017 ROW DEFICIENCY PROJECT	1-1232-00-17									
CAT 12 - SMART WIRES INTERCONNECT.	10141									
CAT 12 - SOLAR INTERCONNECT. (CIAC)	10140									
CL LINE REBUILD	1-1212-07-16									
HIGH PRIORITY REPLACEMENTS	1-1221-90-18									
HONK FALLS SUBSTATION TIE-IN*	1-1212-01-19									
KM/TV REBUILD PROJECTS*	1-1212-15-16									
KNAPPS CORNERS SUBSTATION REBUILD	1-1212-06-16									
NETWORK STRATEGY	1-1212-14-17									
NEW 115KV LINE 12.25MI-ART V11 -H L*	1-1232-70-05									
NEW 115KV LINE-KGN/SAUG-NEAR SB LIN*	1-1232-67-05									
ROW REPAIR PROJECT (DEFICIENCIES)	1-1232-00-18									
SAG MITIGATION	1-1221-90-13									
STORM HARDENING (ER, HR, DR)	1-1212-04-16									
TR LINE RE-ROUTE / RETIREMENT	1-1212-05-17									
TRANSMISSION MINOR PROJECTS	1-1211-00-18									
HG LINE 69KV REBUILD (HONK FALLS - *,**	10261									
Q LINE 69KV REBUILD (PLEASANT VALLE*	10260									
CAT 12 FK LINE 115KV UPGRADE (K-HF)*	10401									
CAT 12 MG AND GK LINE 115KV UPGRADE*	10480									
P LINE 115KV UPGRADE (HF-SP)*	10402									
115KV 5 LINE REBUILD*	10562									
115KV NC LINE REBUILD	10561									
ELECTRIC TRANSMISSION COATING	10564									
	Transmission Subtotal									
SUBSTATION										
COXSACKIE MODERNIZATION*	1-1312-19-18									
FOUR CORNERS MICROGRID	1-1312-08-18									
HONK FALLS GM-737 & HG-709 BKR REPL	1-1312-45-17									
HONK FALLS HG LINE RELAYING UPGRADE	1-1312-19-15									
HURLEY AVE. SDU (SMART WIRES)	1-1312-17-18									
MODENA ADD 115KV BREAKER (RING BUS)*	1-1312-52-17									
NEW KNAPPS CORNERS SUBSTATION	1-1312-50-13									
ROCK TAVERN 115KV BKR REPLACEMENTS	1-1312-23-18									
ROSETON '305' LINE A2 PROTECTION UP	1-1312-16-13									
SOLAR PROJECTS	1-1312-28-17 Xproject name									
	1-1312-28-18 Xproject name									
SUBSTATION BATTERY REPLACEMENT PROG	1-1312-05-18									
SUBSTATION D-SUSTAINING PROJECTS	1-1312-99-19									
SUBSTATION MINOR PROJECTS	1-1311-00-18									
SUBSTATION T-SUSTAINING PROJECTS	1-1312-98-19									
TRAP ROCK SUBSTATION	1-1312-52-16									
WOODSTOCK SUBSTATION REPLACE SWITCH*	1-1312-31-15									
FROST VALLEY ASCO CONTROLLER REPL	1-1312-20-17									
	Substation Subtotal									
NEW BUSINESS										
ELEC. & GAS COMB. URD - BLANKET	1-142L-02-08									
ELEC. N.B. OVERHEAD - BLANKET	1-141L-01-08									
ELEC. URD - BLANKET	1-143L-03-08									
NEW BUSINESS	1-1412-00-12 x project name									
	1-1412-00-15 x project name									
	1-1412-00-16 x project name									
	1-1412-00-18 x project name									
	New Business Subtotal									

Appendix D
Schedule 3 of 3
Central Hudson Gas & Electric Corporation
Case 24-E-0461 and Case 24-G-0462

Program/Project					
DISTRIBUTION IMPROVEMENTS					
4800V CONVER/INFRASTRUCTURE PRG*	1-1551-12-18				
801/802/803/881/882 BEACON PH 4/4	1-1551-23-18				
CATV MAKE-READY	1-1551-01-17 X project name				
	1-1551-01-18 X project name				
CEMI/WORST CIRCUIT RELIABILITY PRG	1-1551-18-18				
COPPER WIRE REPLACEMENT PRG*	1-1551-11-18				
DA - MAJOR PROGRAM *	1-1551-19-18				
DI (1551-0X) - OPERATING/INFRASTR *	1-1551-03-18				
DI (1551-0X) - RELIABILITY	1-1551-10-18				
DI (1551-0X) - THERMAL/VOLTAGE	1-1551-02-18				
DI BLANKETS (15BL-01)	1-151L-01-08				
DI CONVERSIONS (1521-0X)	1-1521-00-18				
DI MINORS (1511-0X)	1-1511-00-18				
DIST POLE REPLACEMENT PROGRAM	1-1551-08-17				
DISTRI IMPR (1551-0X) - OPER/ INFRA	1-1551-03-17				
DISTRIBUTED GENERATION INTERCONNECT	1-1551-23-17				
DISTRIBUTION IMPROVEMENT (1551-0X)	1-1551-01-16 x project name				
	1-1551-03-15 x project name				
DISTRIBUTION IMPROVEMENT CONVERSION	1-1521-00-16				
DISTRIBUTION POLE REPL PRG - 18	1-1551-08-18				
ELEC. DIST IMP. MINOR - CATSKILL	1-1511-01-06				
EMERGENT	1-1551-26-18				
MONTGOMERY SUBSTATION CIRCUIT EXITS	1-1551-21-18				
NETWORK CABLE AND EQUIPMENT	1-1551-15-18				
OVERHEAD SECONDARY REPL PROGRAM	1-1551-04-19				
RD/BRIDGE REBD/RELO PRJ 1531-0X	1-1531-00-18				
RELOCATION BLANKETS (15BL-02)	1-152L-02-08				
ROAD REBLD RELO PROJECTS (1531-OX)	1-1531-00-17				
SOLAR PROJECTS	1-1551-25-18				
URD REPLACEMENT	1-1551-16-18				
CAT 15 - SUB CIRCUIT EXITS	10181				
CAT 15 STORM HARDENING PROGRAM*	10403				
CAT 15 - 5KV AERIAL CABLE *	10440				
CAT 15 DA OTHER	10461				
CAT 15 SECONDARY NETWORK UPGRADE	10462				
STORM CAPITAL	10524				
ELECTRIC - DISTRIBUTION IMPROV. BLAN	1-1511-02-94 x project name				
	1-1540-01-02 x project name				
	Distribution Improvements Subtotal				
TRANSFORMERS					
CAPACITORS	1-1621-00-08				
DISTRIBUTION TRANSFORMERS	1-1611-00-08				
LINE REGULATORS	1-1631-00-08				
NETWORK PROTECTORS	1-1641-00-08				
	Transformers Subtotal				
METERS					
ELECTRIC METERS	1-1731-00-08				
METERING INSTRUMENT TRANSFORMERS	1-1721-00-08				
	1-1721-00-09				
SPECIAL ELECTRIC METER INSTALLATION	1-1711-00-08				
	Meters Subtotal				
STORM					
	1-191L-01-08				
	Storm Subtotal				
Total Electric					

Program/Project					
GAS					
TRANSMISSION					
MAJORS-GAS TRANSMISSION	2-2212-00-18				
MINORS- GAS TRANSMISSION	2-2211-00-18				
CAT 22 MEGA RULE	10463				
Transmission Subtotal					
REGULATOR STATIONS					
MAJORS - GAS REGULATOR STATIONS	2-2312-00-18				
MINORS - GAS REGULATOR STATIONS	2-2311-00-18				
Regulator Stations Subtotal					
NEW BUSINESS					
GAS MAINS NEW BUSINESS - SYSTEM	2-241L-00-06				
GAS NB - COMMERCIAL CONVERSIONS	2-2421-00-18				
GAS NB - SIMPLY BETTER - RES	2-2431-00-18				
GAS NB - TRADITIONAL NEW BUSINESS	2-2411-00-15				
	2-2411-00-18				
GAS NEW BUS LOCALS & SERV BLANKETS	2-241L-00-08				
GAS NEW BUS SPECIFICS MAINS - NEWBU	2-2411-08-14				
New Business Subtotal					
DISTRIBUTION IMPROVEMENTS					
DI-CAP LEAK REPAIR UNIDENT SPECIF	2-2551-04-18				
DI-CI UNDERMINE UNIDENT SPECIF	2-2551-03-18				
DI-HIGHWAY RELO UNIDENT SPECIF	2-2551-02-18				
DI-IDENTIF CI/STEEL MAIN REMOVAL	2-2580-00-18				
DI-IDENTIFIED RELO CI/STEEL REMOVAL	2-2581-00-18				
GAS DI-CATHODICS	2-2551-01-18				
GAS DI-DIST IMPROVEMENT-LOCALS	2-251L-00-08				
GAS DI-HIGHWAY RELO NON CI OR STL	2-2521-00-18				
GAS DI-IDENT PROJ NON CI OR STL	2-2511-00-18				
GAS DI-SERVICE REPS - BLANKETS	2-251L-01-08				
LEAK PRONE SERVICES	10640				
Distribution Improvements Subtotal					
METERS					
GAS METERS	2-2711-00-08				
GAS METERS - SPECIFIC WORK ORDERS	2-2712-00-18				
SPECIAL GAS METER INSTALLATIONS	2-2721-00-08				
Meters Subtotal					
Total Gas					

Appendix D
Schedule 3 of 3
Central Hudson Gas & Electric Corporation
Case 24-E-0461 and Case 24-G-0462

Program/Project					
COMMON					
LAND & BUILDINGS					
KINGSTON - TURNING LANE	4-4112-18-18				
LAND & BUILDINGS DAILY OPS	4-4112-02-18				
LAND & BUILDINGS SPECIFIC PROJECTS	4-4111-00-18				
LINEMEN AND GAS TRAINING CENTERS	4-4112-04-19				
MINORS - DAILY OPERATIONS ELECTRIC	4-4111-10-18				
ARCHITECTURAL/ENGINEERING DESIGN	10568				
DAILY OPERATIONS FLOORING	4-4111-11-18				
DAILY OPERATIONS HVAC	4-4111-12-18				
EV CHARGING INFRASTRUCTURE	10565				
EXTERIOR DOOR REPLACEMENTS	10566				
PAVING	4-4112-01-08				
SOLAR SYSTEM ON COMPANY FACILITIES	10567				
Land & Buildings Subtotal					
OFFICE EQUIPMENT					
MAJOR OFFICE EQUIPMENT	4-4212-00-18				
OFFICE EQUIPMENT MINOR (BLANKET 42-	4-421L-00-08				
HYBRID WORKSTATIONS	10570				
OFFICE CHAIR REPLACEMENT PROGRAM	10569				
Office Equipment Subtotal					
SOFTWARE					
CAT 4220 - APPLICATION SERVICES	10185				
CIS MODERNIZATION	4-4220-27-18				
IT - ENGINEERING INITIATIVES	4-4220-35-18				
CAT 4220 - CIS/CX PROJECT	10182				
CAT 4220 - ERP	10184				
CAT 4220 - EWAM	10183				
SOA IVR INTERFACES	4-4220-42-16				
4220 CYBER SOFTWARE	10303				
4220 IEDR IMPLEMENTATION PHASE I	10304				
Software Subtotal					
HARDWARE					
IT HARDWARE	4-4222-00-18				
Hardware Subtotal					
EMS HARDWARE					
MISCELLANEOUS HARDWARE AND SOFTWARE	4-4230-05-18				
DMS UPGRADE AND OMS IMPLEMENTATION	4-4230-02-18				
EMS Hardware Subtotal					
EMS SOFTWARE					
DMS - RETROFITS FOR EXISTING DA DEV	4-4235-02-18				
EMS Software Subtotal					
SECURITY					
SECURITY PROGRAMS	4-4240-00-18				
Security Subtotal					
TOOLS					
TOOLS AND WORK EQUIPMENT - (BLANKET	4-431L-00-07				
	4-431L-00-08				
TOOLS AND WORK EQUIPMENT - SPEC. MI	4-4311-00-18				
Tools Subtotal					
COMMUNICATIONS					
NETWORK STRATEGY	4-4412-00-17				
	4-4412-00-18				
Communications Subtotal					
TRANSPORTATION					
MOBILE TOOLS - MAJORS	4-4522-00-18				
MOBILE TOOLS - MINORS	4-4521-00-18				
TRANSPORTATION - MINORS	4-4511-00-18				
Transportation Subtotal					
Total Common					
TOTAL					

*CLCPA Phase 1 Projects **CCRP Project (shown as example for denotation)

Appendix E, Schedule A
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462

2025-2028 Construction Forecast ($000's)
(with inflation and AFUDC)

		2025	2026	2027	2028	2025-2028 Total
ELECTRIC PROGRAM						
Production	**11**	6,020	5,358	3,775	5,962	21,115
Transmission	**12**	27,856	28,342	25,881	25,480	107,560
Substations	**13**	26,306	25,830	32,440	31,989	116,566
New Business	**14**	14,504	14,969	15,147	15,331	59,951
Dist. Improvements	**15**	59,057	61,156	56,737	57,304	234,255
Transformers	**16**	16,544	16,908	17,280	17,643	68,375
Meters	**17**	2,555	2,609	2,658	2,709	10,530
Storm	**19**	1,606	1,640	1,671	1,703	6,621
Total Electric Program		154,449	156,812	155,589	158,122	624,972
GAS PROGRAM						
Production	**21**	-	-	-	-	-
Transmission	**22**	5,368	6,147	5,211	3,890	20,615
Regulator Stations	**23**	3,398	4,161	4,681	5,039	17,280
New Business	**24**	12,395	4,465	3,939	3,862	24,661
Dist. Improvements	**25**	57,380	66,919	59,788	62,080	246,168
Meters	**27**	2,770	2,788	2,897	3,110	11,565
Total Gas Program		81,311	84,480	76,516	77,982	320,288
COMMON PROGRAM						
Land & Buildings	**41**	14,339	23,304	18,368	20,829	76,839
Office Equipment	**4210**	547	1,684	631	190	3,052
Operational Technology	**4230/4235**	3,482	5,276	4,346	828	13,932
Hardware & Software	**4222/4220**	39,707	31,363	26,144	19,982	117,197
Security	**4240**	873	690	487	600	2,651
Tools	**43**	1,568	1,705	2,059	1,770	7,102
Communication	**44**	8,830	11,310	12,429	5,935	38,504
Transportation	**45**	12,982	13,248	13,502	13,759	53,491
Total Common Program		82,329	88,581	77,967	63,893	312,769
CORPORATE TOTAL		318,089	329,873	310,071	299,997	1,258,030
REMOVALS		16,286	13,398	13,507	13,559	56,750
TOTAL CAPITAL		334,375	343,271	323,578	313,555	1,314,779

Appendix E, Schedule B
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Electric Capital Expenditures
($000)

Electric Production (Category 11)	2025	2026	2027	2028
Dashville Major Overhaul #1	4,754	-	-	-
Dashville Major Overhaul #2	549	4,896	-	-
Dashville Staircase to Bottom Door	-	108	-	-
Dashville Walkway over Tailrace	-	167	-	-
Dashville Facility Camera System	524	-	-	-
Sturgeon Pool Remote Start	40	30	1,224	-
Dashville Remote Start	-	-	89	508
Sturgeon Pool Relay Protection / Breakers	-	-	1,058	794
Sturgeon Pool Replace Toe of Dam	-	-	-	1,243
Upgrade Excitation Systems at all Sites	-	-	-	336
Sturgeon Pool Retaining Wall Penstock	-	-	-	1,853
Hydro SCADA - New Com Link	-	-	-	-
Sturgeon Pool Tailrace Gates	-	-	-	-
Sturgeon Pool Southern Wall Foundation Reinforcement	-	-	1,186	-
Sturgeon Pool Coating System for inside penstocks	-	-	-	-
Sturgeon Pool Syphon Pit Redesign (TBD)	-	-	-	-
High Falls Facility Camera System	-	-	-	998
Miscellaneous Minor Hydro projects	153	156	218	230
Retirement of S. Cairo	-	-	-	-
Retirement of Coxsackie	-	-	-	-
Emergent Projects	-	-	-	-
Total	**6,020**	**5,358**	**3,775**	**5,962**

Electric Transmission (Category 12)	2025	2026	2027	2028
High Priority Replacements (Various)	4,617	4,790	4,840	5,011
FV Line Indian Lake Crossing - Eversource	-	-	-	-
115kV DW Line - West Balmville WN / 4012 Underbuild	67	1,785	-	-
Transmission Minor Projects	211	219	222	230
Electric Transmission Structure Coating Program	1,361	1,152	471	488
MG and GK Line 115kV Upgrade (Modena - Kerhonkson)	-	-	-	-
FK Line 115kv Upgrade (Kerhonkson - High Falls)	-	-	-	-
P Line 115kV Upgrade (High Falls - Sturgeon Pool)	-	-	-	-
ROW Repair Project (Deficiencies)	432	448	452	468
Honk Falls Substation Tie-in (Kerhonkson Autotransformers)	-	-	-	-
ACSR Conductor Replacement Program, FV - Part 102C	-	-	-	-
Knapps Corners Substation Tie-in (115kV KB & SK Lines)	-	-	-	-
Trap Rock Substation Tie-in and TR Line retirement	-	-	971	-
69kV KM Line Rebuild - Knapps to Myers - 102	-	-	-	-
SB Line: New 115kV Line - Hurley Ave. to Saugerties - Article VII: 11.11 miles	-	-	-	-
H Line: New 115kV Line - Saugerties to N.Catskill - Article VII: 12.25 miles	14,564	6,192	-	-
HG Line: New 69kV Line - Honk Fallls to Neversink - Part 102C	5,463	11,319	11,433	9,553
Retirement of O & OB Line Section from Dashville Tap to Ohioville	-	-	-	-
Q Line: New 115kV Line - Pleasant Valley - Rhinebeck	647	647	671	9,496
Removal of SD / SJ and WM Tap Lines	-	-	-	-
69kV GM Line: Retirement of Clinton Avenue Tap Section	62	-	-	-
115kV SK Line Rebuild	-	112	226	234
115kV 5 Line Rebuild	432	1,679	6,594	-
115kV NC Line Rebuild - FERC AOC Project	-	-	-	-
115kV CN Line Rebuild	-	-	-	-
NW Line 345/115/69 Station Connection & 1.2 Mile NW Line 115kV Rebuild	-	-	-	-
Total	**27,856**	**28,342**	**25,881**	**25,480**

Electric Substation (Category 13)	2025	2026	2027	2028
Substation Minor Projects	560	561	576	604
Substation Battery Replacement	204	102	209	110
Coxsackie - DEC Peaker Regulation Project (Transformer Only) (1-1312-99-19)	1,032	-	-	-
Greenfield Rd. - Substation Upgrade (Reuse Kerhonkson & Modena Transformers) (1-1312-99-19)	1,032	-	-	-
Merritt Park PLC Replacement (1-1312-99-19)	722	-	-	-
New Baltimore Upgrade & DEC Peaker (12MVA XFMR, Relays, 15kV BKRS, D-VAR) (1-1312-99-19)	2,064	-	-	-
South Cairo - DEC Peaker Regulation Project (D-VAR & Transformer) (1-1312-99-19)	3,096	-	-	-
Westerlo - Close FW-1500-NW Breaker (Part of D-VAR Project)	103	-	-	-
Lincoln Park - Relay Upgrade & BRP (115 kV - LR-1219-HP, HP-1318) (1-1312-99-19)	301	-	-	-
Milan PLC Replacement (Strain Bus Replacements, EP 2023-003) (1-1312-99-19)	1,520	-	-	-
Mobile Switchgear (1-1312-99-19)	1,520	-	-	-
Neversink (15 kV - W-1128, CKT-391) (1-1312-99-19) BRP	204	-	-	-
P Line Moved to 115kV Bus (Sturgeon Pool) (1-1312-99-19)	76	-	-	-
Terminal Upgrade Work for 115kV Loop (High Falls) (1-1312-99-19)	76	-	-	-

Appendix E, Schedule B
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Electric Capital Expenditures
($000)

Tinkertown - Replace 7022, 7025 Risers (EP 2023-02) (1-1312-99-19)	151	-	-	-
East Walden Relay Upgrade (1-1312-99-19) ESPIP	-	306	-	-
Fishkill Plains Relay Upgrade (1-1312-99-19) ESPIP	-	612	-	-
Grid Mod - Multiple Substations (1-1312-99-19)	835	443	722	-
Highland Relay Upgrade (1-1312-99-19) ESPIP	-	184	-	-
Maybrook Transformer Upgrades (1-1312-99-19)	4,026	7,139	-	-
Millerton Relay Upgrade (1-1312-99-19) ESPIP	-	163	-	-
North Chelsea PLC Replacement (1-1312-99-19)	-	1,531	-	-
Reynolds Hill Relay Upgrade (1-1312-99-19) ESPIP	-	367	-	-
Sand Dock - Add Breaker For Tilcon (1-1312-99-19)	-	816	-	-
Todd Hill Relay Upgrade (1-1312-99-19) ESPIP	-	265	-	-
Wiccopee Relay Upgrade (1-1312-99-19) ESPIP	1,205	-	-	-
Barnegat Relay Upgrade (1-1312-99-19) ESPIP	-	-	890	-
Converse Street Relay Upgrade, Switchgear, Transformer, RTU Replacements (1-1312-99-19)	-	309	2,937	-
Dashville Relay Upgrade (1-1312-99-19) ESPIP	-	-	157	-
East Kingston PLC Replacement (1-1312-99-19)	-	204	1,781	-
Neversink Relay Upgrade (1-1312-99-19) ESPIP	-	-	168	-
Pulvers T#1 69-13.8kV Replacement (EP 2022-013) (1-1312-99-19)	-	2,045	1,047	-
Sand Dock Relay Upgrade (1-1312-99-19) ESPIP	-	102	943	-
Staatsburg BM85 RTU Replacement (1-1312-99-19)	-	-	628	-
Myers Corners Switchgear Upgrade & 69kV Breaker TV-399-KM Repl (1-1312-99-19)	102	-	3,142	1,099
Ancram Replacement from EC Spare, Replace EC Spare (1 Phase 34.5/13.8kV) (1-1312-99-19)	-	-	524	4,394
Galeville PLC Replacement (1-1312-99-19)	-	-	105	989
Montgomery St. 14kV Switchgear Upgrade (1-1312-99-19)	51	102	2,095	824
Saugerties PLC Replacement (1-1312-99-19)	-	-	-	1,099
Smithfield Relay Modernization (1-1312-99-19)	-	102	1,912	879
Westerlo BM85 RTU Replacement (1-1312-99-19)	-	-	-	549
Sand Dock (15 kV - 10 Breakers) (1-1312-99-19) BRP	-	-	-	-
Spackenkill PLC Replacement (1-1312-99-19)	-	-	-	-
Tinkertown T#1 & T#2 Replacements (EP 2023-02) (1-1312-99-19)	-	1,534	-	-
Tioronda Switchgear Replacement (1-1312-99-19)	-	-	566	1,099
Balmville - Retire Substation (1-1312-99-19)	-	-	-	-
Clinton Ave. - Retire Substation (1-1312-99-19)	-	-	-	-
South Wall Street - Retire Substation (EP 2023-003) (1-1312-99-19)	-	-	-	-
Forgebrook Substation Rebuild (1-1312-99-19) ESPIP	-	511	2,095	2,197
Hibernia (69 kV - E-972) (1-1312-99-19) BRP	-	-	-	-
Hurley Avenue - 115-13.8 kV 13.4/17.9/22.4 MVA Transformer & Switchgear (1-1312-99-19)	-	-	-	2,713
Jansen Avenue Substation Upgrade, GE Harris RTU Replacement, BRP (15 kV - 9 Breakers) (1-1312-99-19)	-	-	105	3,092
Lawrenceville Relay Upgrade (1-1312-99-19) ESPIP	-	-	-	-
Reynolds Hill (15 kV - TD-6001, TD-6005) - Evaluate Switchgear Purchase (1-1312-99-19) BRP	-	-	-	-
Rock Tavern 115 kV Relay Upgrade (1-1312-99-19) ESPIP	-	-	-	220
Shenandoah Relay Upgrade, BRP (15 kV - 25 Breakers) (1-1312-99-19)	102	-	-	-
345kV Switch Replacement Program (1-1312-98-19)	509	510	524	549
115kV Switch Replacement Program (1-1312-98-19)	606	619	630	642
Kerhonkson 115/69kV Autotransformers Phase 1 (1 - 56MVA) (1-1312-98-19)	-	-	-	-
Pot Heads - East Chelsea (1-1312-98-19)	2,064	-	-	-
Pot Heads - West Danskammer (1-1312-98-19)	2,064	-	-	-
Kerhonkson 115/69kV Autotransformers Phase 2 (1 - 56MVA) (Remove 61850) (1-1312-98-19)	1,520	-	-	-
Hurley Ave. 345kV Relay Upgrade (1-1312-98-19) ESPIP	-	1,020	-	-
Rock Tavern 345kV 311 Line A2 Relay Upgrade (1-1312-98-19) ESPIP	-	245	-	-
Roseton 345kV 311 Line A2 Relay Upgrade (1-1312-98-19) ESPIP	-	245	-	-
Pleasant Valley 115kV Modernization (Package Sub & Relays) (1-1312-98-19)	-	-	524	4,394
Rock Tavern 345kV Relay Upgrade (1-1312-98-19) ESPIP	-	-	2,304	604
Roseton 345kV Relay Upgrade (1-1312-98-19) ESPIP	-	-	-	-
Woodstock - Switchgear Replacement (New Transformers) (1-1312-31-15)	100	4,079	3,142	3,296
Modena - Add 3rd Bkr to Complete 115kV Ring Bus (see P&MK memo) (1-1312-52-17)	402	1,204	1,571	-
Tilcon - Tap Station (1-1312-52-16)	60	510	3,142	2,637
Total	**26,306**	**25,830**	**32,440**	**31,989**
Electric New Business (Category 14)	**2025**	**2026**	**2027**	**2028**
New Business	4,865	3,432	3,758	3,140
Bellefield (2024-)	1,141	399	-	-
Cresco (2026)	-	915	-	-

Appendix E, Schedule B
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Electric Capital Expenditures
($000)

Hudson Heritage (2026)	-	572	337	-
Coeymans Industrial Park (2025)	572	1,144	1,685	-
Unidentified warehouse, production	571	915	1,685	4,416
Elec. N.B. Overhead - Blanket	6,230	6,430	6,507	6,586
Elec. & Gas Comb. URD - Blanket	614	634	641	649
Elec. URD - Blanket	512	528	534	541
Total	**14,504**	**14,969**	**15,147**	**15,331**
Distribution Improvements (Category 15)	**2025**	**2026**	**2027**	**2028**
Distribution Improvement Blankets (15BL-01)	29,069	29,735	30,377	29,503
Relocation Blankets (15BL-02)	247	252	257	262
Distribution Improvement Minors (1511-0X)	71	72	74	75
Distribution Improvement Conversions (1521-0X)	382	390	397	405
Road/Bridge Rebuild Relocation Projects (1531-0X)	1,178	1,202	1,226	1,249
CATV Make-ready	4,475	4,568	736	750
Overhead Secondary Replacement Program	259	264	270	275
Distribution Pole Replacement Program	1,178	1,202	1,226	1,249
Distribution Automation - Other	589	601	613	625
Distribution Automation - Major Program	524	-	-	-
Distribution Improvement (1551-0X) - Thermal / Voltage	706	-	-	-
Distribution Improvement (1551-0X) - Reliability	1,501	1,293	1,318	1,499
CEMI/Worst Circuit Reliability Program	1,055	1,078	1,102	1,125
Resiliency Program	-	2,706	-	-
Distribution Improvement (1551-0X) - Operating/ Infrastructure Condition	1,390	1,478	3,588	5,245
5kV Aerial Cable Replacement Program	118	-	-	-
Copper Wire Replacement Program	-	1,052	1,257	999
4800 V Conversion/Infrastructure Program	3,038	3,111	2,746	2,623
Network Cable and Equipment	618	631	645	659
Secondary Network Upgrade Program (All Districts)	1,537	2,126	2,145	500
URD replacement	6,748	3,722	5,116	6,295
CAT 15 - Sub Circuit Exits	1,472	2,705	613	874
Storm Hardening	2,826	2,889	2,952	3,014
Pole wrap installations (CCRP)	78	78	78	78
Total	**59,057**	**61,156**	**56,737**	**57,304**
Transformers (Category 16)	**2025**	**2026**	**2027**	**2028**
Transformers - New Business				
Capacitors				
Regulators				
Total	**16,544**	**16,908**	**17,280**	**17,643**
Electric Meters (Category 17)	**2025**	**2026**	**2027**	**2028**
X041A - Special Meter Installations	199	203	207	211
X042A - Instrument Transformers	414	422	430	439
X043A - Electric Meters	1,943	1,983	2,021	2,060
AMI Pilot	-	-	-	-
Total	**2,555**	**2,609**	**2,658**	**2,709**
Storm (Category 19)	**2025**	**2026**	**2027**	**2028**
Storm	1,606	1,640	1,671	1,703
Total	**1,606**	**1,640**	**1,671**	**1,703**
Grand Total	**154,449**	**156,812**	**155,589**	**158,122**

Appendix E, Schedule C
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Gas Capital Expenditures
($000)

Gas Transmision (Category 22)	2025	2026	2027	2028
Cathodic Test Stations	42	43	44	45
Transmission ROW Capital Improvements	106	108	111	113
AH Line Zinc Ribbon Installations (H&SB coordination)	-	-	-	-
Class Location Line Valves (AH9A,17A,20A)	687	700	-	-
Remote Operated Valves	213	218	668	455
AH Line Valve Replacements (AH2,3,4,5,6,7,9,15,16)	580	593	1,819	1,239
Gate Station PLC Replacements	425	434	444	454
TP Line Identifed Segment Replacements (1,2,3,4,5.1,5.2,6,7,8,9)	3,066	3,448	1,051	1,583
TPC Line Relocation	-	-	-	-
Poughkeepsie Receival MP/TP Interconnect	248	602	1,074	-
Total	**5,368**	**6,147**	**5,211**	**3,890**
Regulator Stations (Category 23)	**2025**	**2026**	**2027**	**2028**
Station Retirements	-	-	-	-
Pressure Control Improvements	279	285	163	167
Pressure Recording Chart Replacements	206	211	217	222
Regulator Station SCADA Implementation	103	106	109	111
Regulator Station Coatings	258	264	272	278
Barclay Heights Regulator Station Rebuild	425	-	-	-
Athens Heater Installation	425	-	-	-
Saugerties Inlet Piping & Heater	351	-	-	-
Monument Square Regulator Station Rebuild	928	-	-	-
Clark St Regulator Station Rebuild	340	-	-	-
South Gate Estates Property Purchase	83	-	-	-
Mill St Heater Installation	-	422	-	-
Glasco Regulator Station Rebuild	-	349	-	-
Hopewell Heater Replacement	-	422	-	-
Catskill Heater Replacement	-	422	-	-
South Street Property Purchase	-	84	-	-
North Cornwall Regulator Station Rebuild	-	1,246	-	-
South Gate Estates Rebuild	-	349	-	-
Cochecton Heater Installation	-	-	434	-
Riverside Road Heater Replacement	-	-	434	-
All Angels Hill Road Heater Replacement	-	-	434	-
John Street Regulator Station Rebuild	-	-	358	-
South Street Regulator Station Replacement	-	-	978	-
Violet Avenue Regulator Station Rebuild	-	-	1,282	-
Hughsonville Regulator Station Rebuild	-	-	-	999
Blue Point Heater Installation	-	-	-	444
Vails Gate Regulator Station Rebuild	-	-	-	999
Vassar Farms Regulator Station Rebuild	-	-	-	366
IBM East Fishkill Station Rebuild	-	-	-	999
Fleetwood Drive Regulator Station Rebuild	-	-	-	366
Middlehope Property Purchase	-	-	-	89
Total	**3,398**	**4,161**	**4,681**	**5,039**
Gas New Business (Category 24)	**2025**	**2026**	**2027**	**2028**
GAS NB - TRADITIONAL NEW BUSINESS	2,730	1,354	1,194	1,171
GAS MAINS NEW BUSINESS - SYSTEM	-	-	-	-
GAS NEW BUS LOCALS & SERV BLANKETS	5,965	2,883	2,543	2,494
GAS NB - COMMERCIAL CONVERSIONS	181	90	79	78
GAS NB - SIMPLY BETTER - RES	278	138	122	119
Greenhaven Correctional	3,241	0	0	0
Total	**12,395**	**4,465**	**3,939**	**3,862**
Gas Distribution (Category 25)	**2025**	**2026**	**2027**	**2028**
Corrosion Control	181	185	190	194
Highway Relocation non LPP	241	246	252	257
Service Replacement Blankets - Emergent	4,613	4,715	4,819	4,925
Isolated Service Replacement Blankets	-	-	-	-
Local Orders -Operational	398	407	416	425
Road Rebuild - Includes Paving Proj	5,611	5,735	5,861	5,990

Appendix E, Schedule C
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Gas Capital Expenditures
($000)

Cast Iron Undermines	179	183	187	191
Unident Leaking - Includes Active Corrosion	1,087	1,111	1,135	1,160
Service Partial/Swing Identified DIPS	3,427	4,936	3,485	2,709
Svce Repl Blankets DIPS	7,913	9,614	5,085	3,601
South Wall Street Area	3,313	-	-	-
NLP- Newburgh Holder	1,225	-	-	-
Garden Smith Foxhall	2,795	-	-	-
Central West Poughkeepsie	2,637	-	-	-
Village of Fishkill - South	1,327	-	-	-
NLP-South St/ N of Fullerton	3,906	-	-	-
PN Line - 9D Wappingers North	3,720	-	-	-
Fairview Station Neighborhood	3,203	-	-	-
Northern Catskill	3,383	-	-	-
Sharon Drive and Route 9	1,354	-	-	-
Fairview and Quarry Street	-	2,561	-	-
NM - South St	-	1,892	-	-
E Poughkeepsie College to Hooker	-	4,385	-	-
NLP/ NM- S. Clark St Neighborhood	-	2,627	-	-
Parker Ave	-	2,237	-	-
Central Kingston	-	5,480	-	-
Uptown Kingston Neighborhood	-	2,603	-	-
Mansion Violet Hamilton	-	3,743	-	-
Wappinger's Falls	-	1,849	-	-
BN Line Replacement	-	3,409	-	-
Midtown Kingston	-	-	3,175	-
Village of Fishkill - North	-	-	1,487	-
Marine Drive to Cornwall 60 PSIG	-	-	3,150	-
MNG South	-	-	3,068	-
NLP- South St Neighborhood	-	-	2,254	-
ME Line- Hwy 17K	-	-	5,607	-
Wappinger's Falls Route 9D	-	-	2,329	-
ME Line- Hwy 32	-	-	3,221	-
PN Line - Wappingers Creek South	-	-	3,693	120
Broome Neighborhood Catskill	-	-	-	2,975
NLP-Carpenter Ave Phase 2	-	-	-	2,684
NM - Creek Run	-	-	-	3,518
North Highland	-	-	-	3,097
Old Mill Howard	-	-	-	2,574
Malden System	-	-	-	4,121
East Beacon	-	-	-	5,621
PN Line - Route 9D Dean Ave South	-	-	-	2,528
PN Line - Route 9D Alpine Drive South	-	-	-	-
Leak Prone Pipe Services - Rate Case Proposal	1,960	2,052	2,134	2,232
Transmission Service to Distribution - Rate Case Proposal	799	1,083	1,266	1,924
Compression Coupling Neighborhoods - Rate Case Proposal	1,569	2,520	3,555	3,783
River/Creek Crossing Reinforcements - Rate Case Proposal	1,105	1,882	1,923	3,145
Highland Falls Reliability Improvement Project	-	-	-	2,775
Reinforcements	1,433	1,465	1,495	1,530
Total	**57,380**	**66,919**	**59,788**	**62,080**
Gas Meters (Category 27)	**2025**	**2026**	**2027**	**2028**
X081A - Gas Meters	2,136	2,140	2,235	2,433
X084A - Special Meter Installation	634	648	662	677
2712-00-18 - Specific Work Orders	-	-	-	-
Total	**2,770**	**2,788**	**2,897**	**3,110**
Grand Total	**81,311**	**84,480**	**76,516**	**77,982**

Appendix E, Schedule D
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Common Other Capital Expenditures
($000)

Land & Buildings (Category 41)	2025	2026	2027	2028
Daily Operations - Electric	101	103	105	107
Daily Operations - Flooring	101	103	105	107
Daily Operations - HVAC	101	103	105	107
Daily Operations - Unidentified	503	514	525	537
EV Charging Infrastructure	259	273	272	299
Exterior Door Replacements	78	82	82	85
Solar System on Company Facilities[A]	174	1,951	642	183
Architectural/Engineering Design	-	-	-	-
Paving	168	177	177	185
Training Academy, Academy	-	-	8,025	14,703
Training Academy, Annex	7,738	12,191	540	-
Newburgh - New Facility	-	-	458	1,676
Transportation Building - EC		453	3,455	-
Bulter Building Rebuild (~ 7500 sq ft)	454	3,437	-	-
Tannersville New Facility (~ 5000 sq ft)	2,000	880	-	-
Building 805/806 Rebuild	-	242	-	-
Ellenville Office Renovation (~ 3000 sq ft)	-	75	1,098	-
POK- Operations Pole barn drainage				
POK- Operations Pole barn concrete floor				
POK- Replace main building exterior lights with tunable LED				
POK- Record Retention Improvments				
KNG- Front lot drainage improvments				
POK- Auditorium Renovation				
POK- Lighting Upgrade - Storeroom				
POK- Upgrade Electric to 801 2nd floor				
POK- Bldg 807 2nd floor testing room HVAC replacement				
EC- Install ceiling and lighting in loading dock area				
POK- Building 801 roof replacement				
NBG- Partial Roof Replacement- Storeroom area				
GNV- Expand yard for storage and install Pole Racks				
POK- Bldg - 800 mens restroom renovation				
Expand Building Managment System controls				
FSH- Video wall building preparation Fishkill Dispatch				
POK- Call Center redesign- design				
POK- New water main and valve Phoenix st				
POK- Replace Training Room HVAC Unit hook up to new controls				
POK- Pave Pole & Equipment area				
KNG- Main level renovation, aud and conf. room				
POK- Bldg 805 Replace Roof				
POK- Record Retention study implementation				
POK- Outdoor picnic patio/Executive lot				
POK- Corp Com area re-configure				
EC- Pave parking by transformer/transportation shop, replace drainage				
POK- Building 805 Resurface and Restripe Garage Floors				
EC- Rehab EC electricians garage (roof, OHDs, wall)				
EC-Renovate Restrooms in Storeroom				
RFN- Replace siding & windows on lodge and office				

Appendix E, Schedule D
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Common Other Capital Expenditures
($000)

KNG- Replace JCI system Kingston lower building
KNG- Replace Rezner heater in Metershop
POK- Exterior lighting upgrades
POK-Bldg 806 - Restroom Renovation
GNV- Expand parking lot
Expand Building Managment System controls
POK- Purchase 1/3 of tanks for Saphire fire protection system
CAT- Install New HVAC Unit (add zone)
POK- install gas boilers in 803 mechanical room, eliminate steam in 803
EC- Replace Storeroom roof
KNG- Front curb & sidewalk
POK- Renovate Sys Ops Restrooms
POK- Replace Window - Bldg 805/806
KNG- Replace JCI system Kingston upper building
POK- Call center redesign
KNG- Replace Carpet Tiles
POK- Bldg 807 - Upper Roof Replacement
KNG- Retaining wall replacement- phase 2 (front)
POK- Bldg 801 - Replace Windows Second Floor
POK- Bldg 810 - Replace 1 Leiberts unit in Computer Room
CAT-Renovate estimating and offices (not breakroom)
KNG- Replace Windows Front Bldg
KNG- Replace Drainage West of rear budiling
POK- Bldg 803 - Replace Carpet on S1 level
POK- Bldg 802 - Replace Windows
POK- Replace JCI Poughkeepsie builing 810
KNG-Repave parking lot
POK- Repave roadway behind building 803, 806 and 810
POK- Install RTU or heat pump for bld. 800 to eliminate steam
EC- Rehab EC construction maint garage (roof, OHDs, wall)
CAT- Replace Generator
POK- Freight Elevator loading dock & Driveway
POK- MultiMedia Studio
POK- Bldg 803 - Replace HVAC Units S1 & S2 level
POK- Bldg. 805 Replace Gas Garage doors
POK- Renovate corp com mens room
POK- Replace damaged fence around facility
CAT- Upgrade garage lighting to LED
CAT- Replace security shed
FSH- Replace security shed
Expand Building Managment System controls
EC- Coat Roof Building 848
POK- Renovate S3 Call Center
KNG- RTU replacement
KNG- Buildout front annex (gas training area)
POK- Bldg. 810 cooling tower upgrade

Appendix E, Schedule D

Central Hudson Gas & Electric Corporation

Cases 24-E-0461 and 24-G-0462

2025 through 2028 Common Other Capital Expenditures

($000)

POK- 810 heat pumps with RTU w/ MERV 13 filter and UV light				
POK- Replace JCI Poughkeepsie builing 807/808				
KNG-Build Maintenance Shop				
EVL- Repave parking lot				
FSH- Renovate south end of building				
NBG- Rebuild Material Bins				
NBG- Replace Flooring				
NBG- Renovate Restrooms				
EC- Coat Roof Building 835				
NBG- Replace Generator				
POK- Building 803 roof replacement				
KNG- Paving				
CAT- Renovate breakroom				
POK- Bldg 803 - Replace Elevator				
POK- Renovate corp com womens room				
POK- Bldg 807 - Replace tile flooring basement level				
KNG-Controls System HVAC				
CAT-Replace HVAC Unit				
Expand Building Managment System controls				
Specific Projects	2,661	2,719	2,779	2,840
Total	**14,339**	**23,304**	**18,368**	**20,829**
Office Equipment (Category 4210)	**2025**	**2026**	**2027**	**2028**
Daily Operations - Misc Furniture	62	63	65	66
Office Chair Replacement Program	20	20	21	21
Hybrid Workforce Model	96	98	100	103
Primary Control Center (42)	-	-	-	-
Training Academy, Annex (15)	-	93	-	-
Training Academy, Annex (training equipment)	327	1,361	407	-
Tannersville- New Facility (7)	42	-	-	-
Transportation Building - EC (3)	-	19	-	-
Bulter Building Rebuild (5)	-	31	-	-
Ellenville Office Renovation (6)	-	-	38	-
Total	**547**	**1,684**	**631**	**190**
Tools (Category 43)	**2025**	**2026**	**2027**	**2028**
Tools	1,568	1,705	2,059	1,770
Total	**1,568**	**1,705**	**2,059**	**1,770**
Transportation (Category 45)	**2025**	**2026**	**2027**	**2028**
Transportaion	12,982	13,248	13,502	13,759
Total	**12,982**	**13,248**	**13,502**	**13,759**
Grand Total	**29,436**	**39,941**	**34,559**	**36,548**

[A] The revenue requirement effect of this investment will be deferred for the return to customers as described in Section V.B.1.xxx.

Appendix E, Schedule E
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Technology Capital Expenditures
($000)

Operational Technology (Category 4230 & 4235)	2025	2026	2027	2028
OT EMS Upgrade Hardware		-	271	-
OT Infrastructure Upgrades	208	211	217	218
OT Ccure Hardware Upgrade		-	217	-
OT DMS Upgrade Hardware		263	-	218
OT Tooling Upgrade 1	-	309	-	-
OT Misc Replacements (4230)	104	79	81	82
OT DMS Upgrade Software	-	719	2,773	
OT ADMS OMS Implementation	2,138	2,460	-	
OT EMS Upgrade Software		-	277	
GE EMS/DMS Historian Implementation and Upgrades		-	-	
OT Visibility & Tool Enhancements 1	-	-	-	-
OT Visibility & Tool Enhancements 2	-	-	-	309
OT Visibility & Tool Enhancements 3	-	332	332	-
OT Visibility & Tool Enhancements 4	-	420	-	-
Grid Mod - ADMS Modeling and Enhancements WOR	882	-		
OT Compliance Automation (CIP-010) & (CIP-005)	150	375	-	-
OT Case Mangement	-	-	179	-
OT Tooling Upgrade 2	-	108	-	-
Total	**3,482**	**5,276**	**4,346**	**828**
Hardware & Software (Category 4222 & 4220)	**2025**	**2026**	**2027**	**2028**
Asset Mgmt - End User Device HW Lifecycle	1,104	1,131	1,191	1,228
Infrastructure HW Lifecycle (Replacement & Storage Upgrades)	1,038	1,107	1,191	1,255
Network Enhancement Project 1	-	782	797	-
Palo Alto HW Lifecycle	-	-	541	546
Network Infrastructure Lifecycle Upgrades / Replacements	415	448	487	546
Luminex Vitual Tape Library Devices - Philadelphia	-	527	-	-
ISE - Major Release Update, Migration to PCC	-	-	-	109
Network sniffer/analyzer	-	101	-	-
Network Monitoring & Asset Mgmt Tool	400	-	-	-
ISE - Enhancements	49	-	-	-
WAN and Internet HW Lifecycle	-	263	271	273
Enhance Network Security Tools	-	-	357	-
Learning Annex		208	211	217
IDF Rebuilds 2024/25	156	-	-	-
Avigilon - West Shore Flow	-	211	-	-
Ville WAN HW Lifecycle	16	-	-	-
Cisco ISE VM Updates	115	-	-	422
Employee Communication Solution	-	105	-	-
IDF Rebuilds 2025	156	-	-	-
Mobile Site WAN Router Renewal	145	158	162	164
IDF Rebuilds 2027	-	-	162	-
IBM Mainframe Disk Storage	-	211	-	218
IDF Rebuilds 2026	-	158	-	-
IDF Rebuilds 2028	-	-	-	180
Auditorium Hardware Upgrade	208	105	-	-
Infrastructure Project Based Expansion	104	121	-	109
Small Switch Upgrades	156	105	108	109
Customer Benchmarking Efficiency	155	-	-	-

Appendix E, Schedule E
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Technology Capital Expenditures
($000)

AMI Project Assessment	-	1,624	-	-
OnBase Upgrade and Enhancements	-	541	-	-
Cygnet Gas Regulator Station Control & System Pressure Monitoring Implementation	-	-	1,007	1,059
IT Application Upgrades	555	602	629	663
Geotab Upgrade and Enhancements	78	-	-	84
Testing Center of Excellence Upgrades and Enhancements	518	541	552	557
SAP PIPO Upgrade and Enhancements	207	-	-	223
FCS Upgrade and Enhancements	-	758	-	-
MV90 Upgrade and Enhancements	-	135	-	-
StormCenter Upgrade and Enhancements	-	108	-	-
TPS (Cash Processing) Upgrade and Enhancements	-	325	-	-
Asset Mgmt - End User Device SW Lifecycle	275	349	395	439
2024 OSCC V11 Upgrade	-	-	276	-
Cygnet Upgrade & Enhancements	124	-	-	134
Damage Prediction Model	-	271	-	-
Middleware Upgrade - SOA (Cloud migration)	207	217	221	223
Records Management Tool Enhancements (Gimmal/E5)	207	-	-	334
Chronus Mentoring Upgrade & Enhancements	-	-	-	28
Datastage Upgrade	-	244	-	-
DIS Replacement	-	363	-	-
Service Now Phase IV -Corporate Knowledge Base Repository (HR)	311	-	-	-
Website Platform Upgrade - Episerver UI Upgrade	155	271	-	-
Annual Bundled Upgrades & Releases of M365 continuous Improvements	104	119	138	145
EmpCenter Cloud Migration Assessment	129	-	-	-
MotioCI Upgrade	21	-	-	-
Case & Point Upgrade and Enhancements	-	-	110	-
RITM0048207 - OnBase (Keymark) Contracts Module: Workflow, Unity Form, Template & DocuSign Modifications Required	-	162	-	-
Mobile App Platform Upgrade	-	217	-	223
Jira Cloud Migration	155	-	-	-
Netmotion Mobility Upgrade	-	188	-	-
Workiva Enhancements and Software Upgrade	104	108	-	111
Microsoft Roadmap: Communication & Collaboration (PBX Replacement)	52	704	-	-
Redwood License Renewal (11/23 & 11/26)	-	650	-	-
RITM0033701 - Fleetwave Rationalization	-	108	-	-
M365: Safety Incident Apps & Analytics	-	271	-	-
ServiceNow SW Model Rationalization	-	-	207	-
Sharepoint orchestration Tool	10	-	-	-
RITM0037305 - Strategic review of Development tooling, DevOps and CI/CD platforms	-	108	-	-
RITM0051202 - Service Now Managed Service Hours	-	271	-	-
App Services Emergent	-	-	-	-
Microsoft Roadmap: Ops Evolution	-	271	-	-
Tagetik Enhancements	570	-	-	-

Appendix E, Schedule E
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Technology Capital Expenditures
($000)

RITM0034235 - DIS Enhancement (for Records Management)	-	217	-	-
RITM0050396 GIS On-Hold Work Order tracking	-	217	-	-
SAP S/4 Hana System Licenses	8,710	-	-	-
Tagetik License Renewal	52	54	55	61
Residential Managed Charging Program Phase 2	311	-	-	-
IEDR Phase II	2,420	2,551	-	-
RITM0047585 - Audit Management Software	-	217	-	223
CX - Kubra Enhancements - (DCX)Payment Experience vendor. eBill, Bill Presentment and Bill Print	-	518	1,083	-
SAP Major System Upgrade & Enhancements	1,657	758	773	780
Cx - Mobile Upgrade and Enhancements	104	-	-	-
Spanish Customer Bill	518	-	-	-
Spanish Forms and Letters	311	-	-	-
CDG Developer Portal	-	-	307	-
Complex Billing and other Regulatory Requirements	259	271	276	279
Website and MyAccount Portal refresh	-	-		-
CIS/CX Emergent	-	-	-	-
Customer Bill Redesign	-	-	-	170
CX - ADA Assessment (Web/Mobile)	-	-	-	118
CX - Centralized Preferences Notifications	284	-	-	-
CX - Chatbot Enhancements (Quarterly Bundles)	-	-	-	-
CX - Mobile App Upgrades (CX) - Account Settings/Contact Info	-	-	-	-
CX - Mobile App Upgrades (CX) - DPA Application	-	-	-	-
CX - Mobile App Upgrades (CX) - Push & Email Notifications	-	-	-	-
CX - Web Upgrades (CX) - Digital Welcome Kit for new Customers	-	-	-	-
CX - Web Upgrades (CX) - Email form for updating account owner name	-	-	-	-
CX - Web Upgrades (CX) - Landlord, Business, Contractor, Developer Experience	-	-	-	-
IVR Modernization - Including Visual IVR, Voice Recognition and VoiceBots	-	-	2,071	975
J Log Auto Creation (Form)	52	54	-	-
J Log Portal	104	108	-	-
Muni Portal Upgrade & Enhancements	-	-	108	-
Cx - MyAccount Security Improvements	104	-	110	-
CX - Kubra Payment Posting & API Phase 2	-	-	-	217
More Online Energy calculators	-	-	-	-
Online High Bill Investigation Calculator	-	-	-	-
Redundancy 1st Party Call Center	129	-	-	-
Salesforce Retirement	-	-	-	-
Street lights out Reporting (GIS Map)	-	-	-	223
Perimeter Security Enhancements 1	125	-	-	-
Perimeter Security Enhancements 2	-	212	-	-
Bitbucket to Github	-	-	-	-
TPRM Enhancements	120	338	106	-
Network Enhancements	-	521	-	-
Security Operations Tooling Enhancements Phase 1	409	417	478	217

Appendix E, Schedule E
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Technology Capital Expenditures
($000)

Acceleration of Security Capability Enhancement Project 1 & CoSourcing	2,500	300	300	300
Security Hardening Project 1	-	77	-	-
Security Enhancement Project 2	26	104	-	-
Security Tool Enhancement Project 1	306	-	-	-
Security Tool Enhancement Project 2	460	469	-	-
Device Management	-	-	-	-
Network Visibility & Segmentation Phase 2	-	-	237	-
Security Tooling Enhancements	204	52	-	54
IDAM System Upgrade & Enhancements	82	156	-	162
Cloud Access Security Broker (CASB)	51	156	-	-
Corporate Password Manager	-	209	212	217
Security Tool Enhancement Project 3	128	130	133	135
ServiceNow Phase V - GRC Tool - Policy & Compliance Mgmt - Vendor Management Module and Upgrades and enhancements	613	209	-	217
Attack Surface Management/Reduction	-	-	475	-
Identity & Access Management (IDAM) Phase 2 - SAP GRC & Servicenow	357	-	-	-
Vulnerability Management Enhancements	-	159	162	-
User Awareness Training	-	-	109	-
Cybersecurity Emergent	-	-	-	-
ISE Phase IV - Cisco Stealthwatch Implementation	102	104	-	-
ServiceNow Phase III - CMDB, Vulnerability Mgmt, Service Mapping	400	175	-	378
Security Capability Enhancement Project 2		275	275	300
Security Capability Enhancement Project 3		171	223	50
ERP Phase III - ERP Transformation	-	-	-	-
ERP Phase III - Finance Assessment & RFP	-	-	-	-
IEA Replacement	-	-	1,104	780
GTS Upgrade - Cloud - Upgrade and Enhancements	621	-	-	334
JDXpert Implementation	192	38	-	-
New Candidate Background Check Vendor			25	-
Electric Bid - to - Bill System (Develop Requirements Document)	-	-	-	-
IEA Replacement Assessment and RFP	52	-	-	-
EmpCenter Upgrades & Enhancement	645	-	-	-
Psuedo Knowledge Mangement System Implementation	-	-		311
Ceridian (Tax Vendor) Replacement	104	-	-	-
Training System Rationalization (Workday, HSI, QTS)		-	-	259
Gas Bid - to - Bill System (Develop Requirements Document)	-	-	-	-
ARCOS Storm Staffing and Enhancements and SSO	-	-	-	-
Workday 3/6 Month Appraisal Project		-	-	155
Workday Enhancements & HR Process Optimizations (Post & Bid)	-	-	-	-
Employee Recognition - Achievers	-	-	-	-
ERP Emergent	-	-	-	-
Incident Reporting Dashboard Enhancements - (Spill report and Dispatch Turnover log Feature)	-	-	-	-

Appendix E, Schedule E
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Technology Capital Expenditures
($000)

Real Property Services Forms DB	-	-	-	-
Safety Recognition Program - Webforms	-	-	-	-
Total HR Data Archival & Process Removal to Retire	-	-	-	-
Knowledge Management System Assessment	-		104	-
Taleo Data Archival & SSO	-	108	-	-
Tesla Contract Expires 12/31/2023 - Renew contract #37696	-	65	-	-
TMS - Travel & Expense Replacement	-	541	-	-
Gas GIS Migration	-	-	1,104	-
PowerPlan Upgrades & Enhancement	311	2,057	751	-
Implement Software in Compliance with FERC 881	103	-	-	-
Fleetwave Upgrades and Enhancements	155	-	-	223
UN - Upgrade and enhance ArcGIS to ArcGIS PRO (for Phase 1 Electric, Phase 2 Gas; Phase3 Fiber)	1,916	1,354	276	-
Project & Portfolio Management Solution (CATV, Enterprise Wide) - PPM Implementation	155	-	-	-
Gas Transmission Integrity Upgrade & Enhancement	647	-	-	864
5 year term License Renewal - December 2026 (SBS - AUD Estimating Designer Software)	-	964	-	-
Used for International trucks, specifically body controllers, proprietary information - provides diagnostic help to mechanics	-	-	-	-
Office Space Management			52	-
Used for all light duty vehicles - provides diagnostics to help mechanics	104	-	-	-
Used for heavy duty vehicles, specific to Cummins engines - provides diagnostics to help mechanics	52	-	-	-
RITM0035780 - Cascade Enhancement to Support Existing Mainframe Functionality			104	-
Implement a Fire Monitoring Software	-	-	-	-
EWAM Emergent	-	-	-	-
License/Contract Renewal - AutoCAD and DWG Trueview Version Upgrade and License Renewals	-	487	-	-
Gas Engineering Assessment/Inspections Business Case			228	-
GIS Upgrades & Enhancements - ARCGis Portal Licences - Expires 02/2025	310	-	-	-
Light Duty Vehicle Diagnostic Equipment	-	-	-	-
M365 - Paperless Data Capture	-	-	207	-
Install Video Wall In Fishkill	-	-	-	-
Implement Facilities Ratings module - eliminate need for another software system	-	54	-	-
Install Video Wall in Newburgh (Projectors)	-	-	-	-
Mobile Workforce Management (MWM) Replacement	3,366	541	-	-
Distribution Transformers and Cut-outs Database	-	-	110	-
Notifi Upgrade & Enhancement	-	146	-	-
RITM0048877 - Esri Electric Distribution Utility Network Advantage Program (UNAP)	-	-	-	-
T/D System Operational Dashboard	-		54	-
Warehouse Barcoding (ERP?)	-	-	-	-
Ongoing Tesco Version Upgrade	-	-	-	-

Appendix E, Schedule E
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
2025 through 2028 Technology Capital Expenditures
($000)

UN - DNV Gas Softwares Upgrade; Inspection Manager (GL Essentials) and Synergi	-	541	-	-
UN - Digital Circuit Mapping - Licenses and Upgrade	518	-	552	-
UN - Underground Network Management GIS Implementation	-	-	552	557
UN - ArcGIS 10.6.1 to 10.8.1 Upgrade	155	-	-	-
CYME Upgrades and Enhancements	-	-	-	334
Emergency Mgmt System Implementation (WebEOC)	219	-	-	261
3 year term Licence Renewal - February 2025 (ArcGIS Portal)	517	-	-	557
UN - Estimating Design SBS AUD Upgrade & Enhancement	518	-	-	557
IT Engineering Inits Emergent	-	-	-	-
Customer MFA & OKTA Upgrade	155	-	-	-
CYME System Implementation / DEW Replacement	-	-	-	111
Distributed Energy Resource Management System Implementation (DERMS)	-	-	4,415	-
Historical Projects	-	-	-	-
Total	**39,707**	**31,363**	**26,144**	**19,982**
Security (Category 4240)	**2025**	**2026**	**2027**	**2028**
Avigilon - Pleasant Valley Substation (5) (4 or 5)	-	-	-	-
Avigilon - Rock Tavern (3)	-	-	-	-
Avigilon - Tuxedo Gate Station	104	-	-	-
Avigilon - East Fishkill Substation (4)	265	-	-	-
Avigilon - Monfort Road Flow Station	297	-	-	-
Avigilon - South Road SOC	-	242	-	-
Security Hardware Lifecycle/Replacements	208	448	487	600
Total	**873**	**690**	**487**	**600**
Communications (Category 44)	**2025**	**2026**	**2027**	**2028**
Net Strat - Router Replacement (4)	684	1,771	3,837	3,720
Net Strat - Grid Mod (6)	5,000	5,835	5,835	862
Net Strat - Backhaul (3)	1,052	1,074	1,453	-
SLA Improvement Projects	-	537	603	615
Net Strat - LMR / DMR (5)	526	537	167	369
Net Strat - Substation Upgrade (1)	1,052	1,288	164	369
Net Strat - Eltings Corner Fiber	200	-	-	-
Deep Packet Analysis Tool	-	-	265	-
Net Strat - District Offices	316	107	-	-
IPAM - Infoblox	-	54	-	-
Network Automation (IT)	-	107	-	-
Netflow Monitoring Tool	-	-	105	-
Total	**8,830**	**11,310**	**12,429**	**5,935**
Grand Total	**52,893**	**48,640**	**43,407**	**27,345**

Appendix F, Schedule 1

Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462

Listing of Deferrals As Identified in Section V.B[1]

Deferral Item	Deferral Method[2]	Carrying Charges[3]
AMP Phase II	Under the terms of Cases 14-M-0565 / 20-M-0266 Order Authorizing Phase 2 Arrears Reduction Program: to effectuate the Phase 2 program, the utilities shall defer the amount of the arrears relief being provided, net of any economic development funds or additional deferrals, for recovery from customers. Central Hudson shall recover AMP Phase II program costs (and related carrying charges) over a 7-year period through a surcharge on customer bills effective April 1, 2023.	Pre-tax Authorized Rate of Return
Asbestos Litigation	Deferral of actual or accrued costs with rate allowance set @ zero. Carrying charges to be applied to actual costs over / under rate allowance only.	Pre-tax Authorized Rate of Return
Asset Retirement Obligation Depreciation and Accretion Expense	Deferral of depreciation and accretion expense incurred on ARO assets and liabilities.	Not applicable
Call Center Legislation	Deferral of incremental costs each rate year incurred to comply with Chapter 107 of the Laws of 2025, based on the following structure: (1) 100% deferral of incremental expenditures associated with hiring of internal or external resources, including but not limited to labor, training, equipment, and office space up to $7.5 million; (2) 50% deferral of incremental expenditures between $7.5 million and $8.5 million; and (3) a limit on deferral of incremental expenditures set at $8.5 million per rate year.	Pre-tax Authorized Rate of Return
Case 14-M-0101 and related Proceedings/Orders: Incremental costs not included in base rates	Deferral of the revenue requirement effect over / under the amount included in rates.	Pre-tax Authorized Rate of Return
CDG Consolidated Billing Deferral	As approved in the Order Regarding Consolidated Billing for Community Distributed Generation in Case 19-M-0463, deferral of incremental costs incurred for the implementation and operation of the net crediting billing model, with an offsetting deferral of amount billed to customers through the discount rate to cover these costs.	Other Customer Capital Rate
Clean Energy Fund	Deferral of actual costs over / under amount collected through Surcharge.	Not applicable to deferral balance as of March 1, 2016; Other Customer Capital Rate for deferral balances accumulated subsequent to March 1, 2016
Climate Change Resilience Plan	Deferral of incremental costs for necessary consultants retained to develop a second round Climate Change Resilience Plan as required by PSL §66(29)(f).	Pre-tax Authorized Rate of Return
Cloud Based or SaaS solutions implemented	The Company is authorized to defer the revenue requirement effect of variations resulting from software solutions chosen that require a different accounting treatment under Financial Accounting Standards Board ("FASB") standards compared to amounts assumed in the establishment of revenue requirements. If a particular solution was projected to be expense, but ultimately the solution chosen does qualify as capital and the service costs are included in Plant in Service, the IT operating expense included in rates associated with the service costs (excluding maintenance) will be deferred for future return to customers. At the same time, the actual capitalized license costs would be excluded in the calculation of actual Net Plant and the associated revenue requirement effect (return on and return of) would be deferred as a reduction to this deferral. Conversely, if a solution is assumed to be capital, but does not ultimately qualify for such treatment, the Company is authorized to defer the IT operating expense. This deferral will be offset by the revenue requirement effect (i.e., return on and depreciation) of the actual project cost assumed in rates, which will be adjusted out of the established net plant targets.	Pre-tax Authorized Rate of Return
Credit / Debit Card Fees and Walk-In Center Fees	Deferral of costs over / under rate allowance (including walk-in center transaction fees and Outreach) related to credit card program.	Pre-tax Authorized Rate of Return
Danskammer Gas Revenue	The Company will defer the amount of actual revenues above or below the $1.0 million revenue imputation in base delivery rates.	Pre-tax Authorized Rate of Return
Deferred Temp Metro Transit Bus Tax Surcharge	Deferral of actual cost over / under the amount collected through Surcharge.	Not applicable
Deferred Unbilled Revenues	Deferral of $5.1M of unbilled revenues to PSC Account 254.32 as required by Order Approving Accounting Change with Modification Effective July 20, 2016, Ordering Clause 2 (page 6).	Not applicable
Deferred Unrealized Losses/Gains on Derivatives	Deferral for mark to market changes for derivatives for the term of each as reflected with an offsetting receivable or payable on the balance sheet. Realized gain or loss is included in purchased electric or purchased natural gas upon settlement.	Not applicable
Deferred Vacation Pay Accrual	Deferral of vacation accrual recorded.	Not applicable
DEI - Proceeding to Review Utilities' Diversity, Equity, and Inclusion Practices (Case 22-M-0314)	Per the terms of the Order Initiating Proceeding in Case 22-M-0314 *Proceeding to Review Utilities' Diversity, Equity, and Inclusion Practices* , Issued and Effective June 16, 2022: While the consultant will work at the direction of Staff, the costs will be paid by the utilities this Order requires to develop DEI plans. Costs associated with the consultant can be deferred with recovery addressed in future rate cases.	Pre-tax Authorized Rate of Return
Earnings Adjustment Mechanisms - Electric	Authorization to defer and recover from customers incentives earned related to earnings adjustment mechanisms targets met.	Not applicable
Earnings Adjustment Mechanisms - Gas	Authorization to defer and recover from customers incentives earned related to earnings adjustment mechanisms targets met.	Not applicable

Appendix F, Schedule 1

Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462

Listing of Deferrals As Identified in Section V.B[1]

Deferral Item	Deferral Method[2]	Carrying Charges[3]
Earnings Sharing Mechanism	The Company will defer earnings in accordance with the provisions established in Section VII of the JP for future disposition by the Company.	Pre-tax Authorized Rate of Return
Economic Development - Electric	Deferral of actual cost over / under the amount collected through rates.	Pre-tax Authorized Rate of Return
Energy Efficiency - Electric & Gas	In accordance with the January 16, 2020 Order in Case 18-M-0084, as amended by the June 23, 2023 Order Approving Funding for Clean Heat Program in Case 18-M-0084, the Company is authorized to defer over/under spending compared to the amended rate allowance. Additionally, the Company maintains the ability to defer overspending capped at the cumulative NENY budgets plus the amount authorized in the June 23, 2023 Order. Future Commission action(s) in the generic EE/BE Proceeding may affect authorized budgets for 2025 and beyond as well as the deferral cap. Provisions from any future Orders will be implemented into the Company's deferral assessment.	Pre-tax Authorized Rate of Return
Energy Efficiency and Heat Pump - Amortization of Regulatory Asset	Deferral of $18.75 million amortized over 10-years as established in Case 23-E-0418.	Not Applicable
Energy Efficiency - Exemptions from Utility Programs	Deferral of differences between electric Energy Efficiency exemptions imputed in base rates and actual Energy Efficiency exemptions provided.	Pre-tax Authorized Rate of Return
Energy Storage Projects	Deferral of revenue requirement effect (depreciation and return on investment) of energy storage projects.	Pre-tax Authorized Rate of Return
Environmental Site Investigation and Remediation Costs	Deferral of actual or accrued costs over / under rate allowance. Carrying charges to be applied to actual costs over / under rate allowance only.	Pre-tax Authorized Rate of Return
EV - DCFC/LMTIP Funding	In accordance with Case 18-E-0138, and subsequently 22-E-0326, the company will continue its deferral of the $4.4 million provided by NYSERDA, as well as the surcharge billed to customers during calendar year 2020 that did not contribute to the SBC. Per the referenced Orders, amounts spent in accordance with programs defined by these orders will be deferred as a reduction of this balance.	Pre-tax Authorized Rate of Return
EV - Time of Use ("TOU")	As prescribed in Case 18-E-0206, the Company is authorized to defer the revenue requirement associated with the incremental cost of TOU meters . If during the term of the Rate Plan, the deferred balance reaches $50,000, it will be included in the Miscellaneous surcharge for recovery from SC1 and SC6 customers over a one-year period beginning the first billing batch of the subsequent February or August. If the balance is less than $50,000 it will be reflected in the balance sheet offset process in the Company's next rate case.	Pre-tax Authorized Rate of Return
EV Make Ready Program Light Duty - Incremental New Business Capital Costs	To the extent that the Company exceeds its Net Plant Targets, the Company can defer the revenue requirement effect (return and depreciation) of New Business capital expenditures specific to this program for future collections.	Pre-tax Authorized Rate of Return
EV Make Ready Program Light Duty - Incremental O&M and Capital Costs Excluding New Business	In accordance with Case 18-E-0138, the Company will defer actual O&M costs specific to this program (e.g. incentives rebated for Customer Owned make ready work, implementation costs, allowable non-utility futureproofing) associated with the EV Make Ready Program. In addition, the Company is authorized to defer the revenue requirement effect (return and depreciation) of Company make ready capital expenditures, excluding New Business related capital expenditures. Costs will be recovered through a surcharge.	Pre-tax Authorized Rate of Return
EV Make Ready Program Medium/Heavy Duty - Incremental New Business Capital Costs	To the extent that the Company exceeds its Net Plant Targets, the Company can defer the revenue requirement effect (return and depreciation) of New Business capital expenditures specific to this program for future collections.	Pre-tax Authorized Rate of Return
EV Make Ready Program Medium/Heavy Duty - Incremental O&M and Capital Costs Excluding New Business	In accordance with Case 18-E-0138, the Company will defer actual O&M costs specific to this program (e.g. incentives rebated for Customer Owned make ready work, implementation costs, allowable non-utility futureproofing) associated with the EV Make Ready Program. In addition, the Company is authorized to defer the revenue requirement effect (return and depreciation) of Company make ready capital expenditures, excluding New Business related capital expenditures. Costs will be recovered through a surcharge.	Pre-tax Authorized Rate of Return
Executive Short Term Incentive Compensation	RY1: Deferral of costs for future collection based on Staff Review and approval of management audit recommendation 2.7. RY2 & RY3: Should management audit recommendation 2.7 not be completed by the end of the respective rate year, the Company will defer the rate allowance for future return to customers.	Pre-tax Authorized Rate of Return
External Rate Case Expenses	Deferral of external expenses amortized over 36 months.	Not applicable
FAS 109	Deferral of tax on basis differences not provided for elsewhere.	Not applicable

Appendix F, Schedule 1

Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462

Listing of Deferrals As Identified in Section V.B[1]

Deferral Item	Deferral Method[2]	Carrying Charges[3]
FERC jurisdictional proceedings: Incremental costs and potential outcomes regarding Hydro facilities	Deferral of incremental O&M expenses and the revenue requirement effect on incremental capital spending incurred in a RY as a result of a FERC proceeding concerning hydroelectric facilities when the total impact is greater than 10BPs of return on common equity for the electric department. In addition, if the Company implements incremental capital related to any such proceeding, the balance will be reduced from actual electric net utility plant prior to comparison to the Net Plant target for calculating the net plant deferral.	Pre-tax Authorized Rate of Return
FERC Wholesale Delivery Service Revenues	Should the Company have customers that take service under the FERC Wholesale Distribution Service tariff associated with Case 22-E-0549 and aligned with FERC Order No. 2222 and No. 841, the Company proposes to defer the associated revenues for future pass-back to delivery service customers.	Pre-tax Authorized Rate of Return
Finance Charges and Reconnection Fee Revenue Deferral	Symmetrical deferral of actual finance charge and reconnection fee revenues above or below the levels included in the final revenue requirement in a Rate Year.	Pre-tax Authorized Rate of Return
Funded Status Adjustment of Pension/OPEB Plans	Deferral of the over/under funded status of the plan at each year-end with an offsetting asset or liability on the balance sheet.	Not applicable
Gas Planning Proceeding - Gas Long-Term Plan	In Rate Year 3, the Company is authorized to defer up to $665,000 related to preparing its next Gas Long-Term Plan in Gas 20-G-0131.	Pre-tax Authorized Rate of Return
Gas Long-Term Plan Proceeding - PA Consulting	The Company's deferral of costs associated with PA Consulting's services regarding the Company's Gas System Long-Term Plan in Case 23-G-0676 shall not include the difference between the actual final billed professional fees of PA Consulting (not to exceed $578,652) and the professional fees set in the original contract ($470,000). The Company may defer PA Consulting's billed expenses, which are limited to $35,250.	Pre-tax Authorized Rate of Return
Governmental, Legislative and Other Regulatory Actions	The Company is authorized to defer the revenue requirement effect of any governmental, legislative, accounting, regulatory, tax or applicable tax rates, fees, government-mandated action or other regulatory actions in a Rate Year whose impact in aggregate is greater than 10 basis points for either the electric department or the gas department.	Pre-tax Authorized Rate of Return
Heat Pump Program	In accordance with the January 16, 2020 Order in Case 18-M-0084, as amended by the June 23, 2023 Order Approving Funding for Clean Heat Program in Case 18-M-0084, the Company is authorized to defer over/under spending compared to the amended rate allowance. Additionally, the Company maintains the ability to defer overspending capped at the cumulative NENY budgets plus the amount authorized in the June 23, 2023 Order. Future Commission action(s) in the generic EE/BE Proceeding may affect authorized budgets for 2025 and beyond as well as the deferral cap. Provisions from any future Orders will be implemented into the Company's deferral assessment.	Pre-tax Authorized Rate of Return
IEDR Proceeding	Deferral of incremental costs, including expenses and the revenue requirement effect (depreciation and return on capital) of capital costs incurred under the Integrated Energy Data Resource Order (Case 20-M-0082). This deferral excludes IEDR Phase 1, as the capital investment is included in Rate Base beginning July 1, 2025. In conjunction with this deferral, to the extent the Company implements incremental capital related to this proceeding, the balance will be reduced from actual electric net utility plant prior to the comparison to the Net Plant targets for the purposes of calculating the net plant deferral since the revenue requirement effect is being deferred for future recovery separately.	Pre-tax Authorized Rate of Return
IPWG (Interconnection Policy Working Group)	Under the terms of Case 20-E-0543, Central Hudson is authorized to defer the revenue requirement effect associated with unsubscribed project costs until such time the costs are included in base rates.	Pre-tax Authorized Rate of Return
Legacy Hydro Revenue	The revenue requirement includes a level of $4.4M revenue / benefit from legacy hydro generation. The Company will defer actual monthly revenue / benefit above or below 1/12th of the imputed Rate Year revenue / benefit. This amount will be refunded or collected on all deliveries through the Miscellaneous Charge Component of ECAM on a current month basis.	Not applicable - Continued treatment within ECAM, deferral of over/under into ECAM Regulatory Asset and included in ECAM working capital carrying charge calculation
Low Income Program - Bill Discount / Energy Affordability Program	Deferral of costs over/ under rate allowance, with any under-expenditures available for future use in the low income / energy affordability program.	Pre-tax Authorized Rate of Return
Low Income Program - Waiver of Reconnection Fee	Deferral of costs over/ under rate allowance, with any under-expenditures available for future use in the low income program.	Pre-tax Authorized Rate of Return
Make Whole Provision	Deferral of any revenue under/over collections resulting from an extension of the suspension period and Commission approval of new rates after July 1, 2025.	Pre-tax Authorized Rate of Return
Major Storm Reserve	Deferral of incremental major storm restoration or prestaging costs as described in Appendix G.	Pre-tax Authorized Rate of Return
Major Storm Amortization	Deferral of $59.9 million amortized over 10-years as established in Case 23-E-0418.	Not Applicable
Net Lost Revenues - Merchant Function Charge	Deferral of actual lost revenues over / under amount forecasted in rates due to migration to Non-RDM classes.	Other Customer Capital Rate

Appendix F, Schedule 1

Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462

Listing of Deferrals As Identified in Section V.B[1]

Deferral Item	Deferral Method[2]	Carrying Charges[3]
Net Plant Targets	The actual electric and gas net plant and depreciation expense, adjusted for investments that are subject to deferral and/or that are required to align actual GAAP results with ratemaking methodology (i.e. treatment of select cloud based license fees), will be reconciled to the combined electric and gas net plant and depreciation expense targets for Rate Year 1, Rate Year 2, and Rate Year 3. If at the end of Rate Year 3 the cumulative revenue requirement impact from net plant and depreciation expense differences is negative, the Company will defer the revenue requirement impact for the benefit of customers. If at the end of Rate Year 3 the cumulative revenue requirement impact is positive, no deferral will be made.	Pre-tax Authorized Rate of Return
Non-Major Storm Expense	The Company will reconcile actual non-major storm expense to the rate allowance at the end of each Rate Year on a cumulative basis. At the end of each Rate Year, if the Company has a net underspend, a deferral for return to customers will be recorded; if the Company has a net overspend, no deferral will be recorded. Any cumulative underspending at the end of Rate Year 3 will be deferred for future return to customers.	Pre-tax Authorized Rate of Return
Non-Pipes Alternative (NPA) Projects	Deferral of revenue requirement effect of costs and incentives incurred during the term of the Rate Year as specified in the Commission's June 14, 2018 Order in Case 17-G-0460.	Pre-tax Authorized Rate of Return
Non-Wires Alternative (NWA) Projects	Deferral of revenue requirement effect of costs and incentives as authorized in the Commission's June 14, 2018 Order in Case 17-E-0459.	Pre-tax Authorized Rate of Return
NYS Corporate Tax Change	Deferral of incremental tax expense resulting from legislative changes. The revenue requirement reflects the New York State budget bill enacted in April 2023. If legislation is extended or amended and the Company continues to be subject to a capital-based tax in 2027, the Company will defer this incremental tax expense for future collection from customers. Additionally, if the legislation is amended or extended with regards to the corporate income tax rate, the Company will defer for future return to or recovery from customers the revenue requirement effect of (1) the change in income tax rate on current tax expense, if any, as well as (2) the re-statement of deferred tax asset and liability balances. These balances will be subject to carrying charges at the PTROR beginning with the date the taxes are paid or balances are re-stated.	Pre-tax Authorized Rate of Return
OPEB	Deferral of expenses over / under rate allowance	Not applicable
Pension and OPEB reserve carrying charges	Deferral of carrying charges on the difference between actual Pension and OPEB reserve levels compared to the reserve levels included in the development of rate base used to establish delivery rates.	Pre-tax Authorized Rate of Return
Pension Plan	Deferral of expenses over / under rate allowance	Not applicable
PermaLock Tapping Tee Assemblies (Case 23-G-0083)	The Company is authorized to defer the revenue requirement effect of incremental costs, including O&M and return on and of capital investments, incurred to comply with any future directives in Case 23-G-0083 regarding the inspection and/or remediation of PermaLock Tapping Tee Assemblies that are not otherwise addressed within generic proceedings	Pre-tax Authorized Rate of Return
Platform Service Revenues	The Company will defer 80% of the Company's share of the revenue earned from sales through the Community Distributed Generation Marketplace ("CDGM") platform for the benefit of customers.	Pre-tax Authorized Rate of Return
Pole Attachment Revenue & CATV/Broadband Make Ready	Deferral of the revenue requirement effect (depreciation and return on investment) for capital costs associated with CATV Fiber Make Ready above amounts reflected in rates as detailed in Case 23-E-0418 Commission Order, adjusted by pole attachment rent revenue over/under that assumed in rates.	Pre-tax Authorized Rate of Return
Property Taxes	For each Rate Year, the difference between the rate allowance for property tax expense (including school, county, city, town, village and special franchise) and actual property tax expense on a Rate Year basis will be deferred for future recovery, or returned to customers, with carrying charges at the PTROR. Differences will be shared 90/10 between customers and the Company, respectively; provided, however, that the Company's pre-tax loss or gain will be limited to five basis BPs per department (electric and gas) for each Rate Year.	Pre-tax Authorized Rate of Return
PSC initiated or Required Management or Operations Audit	Deferral of incremental costs incurred to conduct Commission mandated management or operations audits.	Pre-tax Authorized Rate of Return
Purchased Electric Costs	Deferral of actual costs over / under the amount collected.	Not applicable
Purchased Gas Costs	Deferral of actual costs over / under the amount collected.	Not applicable
Rate Adjustment Mechanism - Electric	Deferral details as described in Appendix H, which defines the thresholds and qualifying deferrals for inclusion.	Other Customer Capital Rate
Rate Adjustment Mechanism - Gas	Deferral details as described in Appendix H, which defines the thresholds and qualifying deferrals for inclusion.	Other Customer Capital Rate
Rate Moderator - Electric	Deferral of the net remaining regulatory liabilities available for future rate moderation.	Pre-tax Authorized Rate of Return
Rate Moderator - Gas	Deferral of the net remaining regulatory liabilities available for future rate moderation.	Pre-tax Authorized Rate of Return

Appendix F, Schedule 1

Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462

Listing of Deferrals As Identified in Section V.B[1]

Deferral Item	Deferral Method[2]	Carrying Charges[3]
Renewable Energy Access and Community Help	As approved in Order 24-E-0084, deferral of incremental costs incurred for the implementation and operation of the REACH program, with an offsetting deferral of amount billed to customers through the discount rate to cover these costs.	Other Customer Capital Rate
Research and Development	Deferral of costs over / under rate allowance	Not applicable
REV Demonstration Projects	Deferral of the revenue requirement effect of REV demonstration projects up to 0.5% of delivery service revenue requirement, or the revenue requirement associated with capital expenditures of $10 million, whichever is larger.	Pre-tax Authorized Rate of Return
Revenue Decoupling Mechanism - Electric	Deferral of actual revenues billed over / under targeted revenues.	Other Customer Capital Rate
Revenue Decoupling Mechanism - Gas	Deferral of actual revenues billed over / under targeted revenues.	Other Customer Capital Rate
Right of Way Maintenance - Distribution	Actual distribution ROW tree trimming expenditures will be compared to the sum of the Rate Year allowances over the three-year term of the Joint Proposal on a cumulative basis. Any cumulative underspending at the end of Rate Year 3 will be deferred for future return to customers.	Pre-tax Authorized Rate of Return
Sales Tax Refunds and Assessments	For any refunds received (net of fees) or assessments paid where the source amounts were charged to expense, the Company will defer this amount for future return to or recovery from customers. The Company will continue to file notice as required under 16 NYCRR 89.3 or include refunds in its PSC Annual Report.	Pre-tax Authorized Rate of Return
Solar on Company Facilities	Deferral of the revenue requirement effect of the capital investments associated with installing solar on company facilities included in the development of revenue requirements.	Pre-tax Authorized Rate of Return
Statewide Solar for All	As approved in Order 21-E-0629, deferral of incremental costs administrative costs associated with implementing the S-SFA program, with an offsetting deferral of amount billed to customers through the admin fee to cover these costs.	Other Customer Capital Rate
Stray Voltage Program	Deferral of actual costs over / under rate allowance	Pre-tax Authorized Rate of Return
Supplemental Gas AMI Study	Deferral of costs associated with a Supplemental Gas AMI Study up to $100,000.	Pre-tax Authorized Rate of Return
TCJA Non-Asset Based EDFIT Balance Amortization	Deferral of non-asset based TCJA EDFIT balances amortized over 10-years as established in Case 23-E-0418 and 23-G-0419.	Not applicable
Theoretical Reserve Amortization	20 year amortization of the book to theoretical reserve adjustment as established in Cases 23-E-0418 and 23-G-0419 .	Not applicable
Uncollectible Reserve Deferral	The Company is authorized to record a deferral to offset the uncollectible reserve on its balance sheet.	Not applicable
Uncollectible Write-offs and Collection Agency Fees	Symmetrical deferral of any differences between the actual 12 months of net write-offs and collection agency fees experienced as compared to the 12 months of billed uncollectibles and the established rate allowance for collection agency fees.	Pre-tax Authorized Rate of Return
Utility Thermal Energy Network pilot project costs as authorized by orders in Case 22-M-0429	Deferral for costs associated with Case 22-M-0429 Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act.	Pre-tax Authorized Rate of Return

NOTES:

[1] While the listing of deferrals in Appendix F is intended to be comprehensive at the time of the JP, the Signatories recognize that other authorized deferral accounting mechanisms may have inadvertently been excluded from this listing.

[2] For purposes of the JP, unless otherwise expressly defined, revenue requirement effect includes revenue, expense, return on capital expenditures, depreciation, applicable property taxes and any other associated taxes and fees.

[3] The pre-tax authorized rate of return for each Rate Year is included in Appendix L, Schedule 1. The Other Customer Capital Rate is provided annually in a letter filed by the Director of the Office of Accounting, Audits and Finance.

Appendix F, Schedule 2
Sheet 1 of 2
CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CASES 24-E-0461 and 24-G-0462
EXAMPLE OF DEFERRAL FOR CLOUD BASED SOFTWARE (CAPITAL) (ILLUSTRATIVE ONLY)

Assumptions:

100,000	IT - Cloud Based Software Expense included in O&M in rates - RY1
150,000	IT - Cloud Based Software Expense included in O&M in rates - RY2
200,000	IT - Cloud Based Software Expense included in O&M in rates - RY3
450,000	IT - Cloud Based Software Expense included in O&M in rates - Total
12,500	Monthly expense*

* For simplicity of example for illustrative purposes, reflected as straight line over 12 months. Actual allocation monthly will be based on sales forecast in rates if deferral is applicable

Assumed accounting treatment requires capital rather than expense treatment

450,000	IT Investment - Cloud Based Software**
12,500	Monthly amortization (3 years, 36 months)

** For simplicity of example for illustrative purposes, reflects purchase and in service July 2025. Actual month placed in service will be used if deferral is applicable

450,000 Adjustment to Net Plant Target

Adjustment to Net Plant Target

Month	Adjustment to Net Plant Target**	AVERAGE NET UTILITY PLANT: Reserve @ BOM	Book Depreciation	Reserve @ EOM	Average Reserve	Average Net Plant	Pre-Tax WACC	Pre-Tax Return on Investment	Book Depreciation Expense	Deferred Revenue Requirement	Cumulative Deferred Revenue Requirement
1	450,000	0	12,500	12,500	6,250	443,750	0.72%	3,177	12,500	15,677	15,677
2			12,500	25,000	18,750	431,250	0.72%	3,087	12,500	15,587	31,264
3			12,500	37,500	31,250	418,750	0.72%	2,998	12,500	15,498	46,762
4			12,500	50,000	43,750	406,250	0.72%	2,908	12,500	15,408	62,170
5			12,500	62,500	56,250	393,750	0.72%	2,819	12,500	15,319	77,489
6			12,500	75,000	68,750	381,250	0.72%	2,729	12,500	15,229	92,718
7			12,500	87,500	81,250	368,750	0.72%	2,640	12,500	15,140	107,858
8			12,500	100,000	93,750	356,250	0.72%	2,550	12,500	15,050	122,908
9			12,500	112,500	106,250	343,750	0.72%	2,461	12,500	14,961	137,869
10			12,500	125,000	118,750	331,250	0.72%	2,371	12,500	14,871	152,740
11			12,500	137,500	131,250	318,750	0.72%	2,282	12,500	14,782	167,522
12			12,500	150,000	143,750	306,250	0.72%	2,192	12,500	14,692	182,214
13			12,500	162,500	156,250	293,750	0.73%	2,152	12,500	14,652	196,866
14			12,500	175,000	168,750	281,250	0.73%	2,060	12,500	14,560	211,426
15			12,500	187,500	181,250	268,750	0.73%	1,969	12,500	14,469	225,895
16			12,500	200,000	193,750	256,250	0.73%	1,877	12,500	14,377	240,272
17			12,500	212,500	206,250	243,750	0.73%	1,785	12,500	14,285	254,557
18			12,500	225,000	218,750	231,250	0.73%	1,694	12,500	14,194	268,751
19			12,500	237,500	231,250	218,750	0.73%	1,602	12,500	14,102	282,853
20			12,500	250,000	243,750	206,250	0.73%	1,511	12,500	14,011	296,864
21			12,500	262,500	256,250	193,750	0.73%	1,419	12,500	13,919	310,783
22			12,500	275,000	268,750	181,250	0.73%	1,328	12,500	13,828	324,611
23			12,500	287,500	281,250	168,750	0.73%	1,236	12,500	13,736	338,347
24			12,500	300,000	293,750	156,250	0.73%	1,145	12,500	13,645	351,992
25			12,500	312,500	306,250	143,750	0.73%	1,051	12,500	13,551	365,543
26			12,500	325,000	318,750	131,250	0.73%	959	12,500	13,459	379,002
27			12,500	337,500	331,250	118,750	0.73%	868	12,500	13,368	392,370
28			12,500	350,000	343,750	106,250	0.73%	777	12,500	13,277	405,647
29			12,500	362,500	356,250	93,750	0.73%	685	12,500	13,185	418,832
30			12,500	375,000	368,750	81,250	0.73%	594	12,500	13,094	431,926
31			12,500	387,500	381,250	68,750	0.73%	502	12,500	13,002	444,928
32			12,500	400,000	393,750	56,250	0.73%	411	12,500	12,911	457,839
33			12,500	412,500	406,250	43,750	0.73%	320	12,500	12,820	470,659
34			12,500	425,000	418,750	31,250	0.73%	228	12,500	12,728	483,387
35			12,500	437,500	431,250	18,750	0.73%	137	12,500	12,637	496,024
36			12,500	450,000	443,750	6,250	0.73%	46	12,500	12,546	508,570
			450,000							508,570	

Deferral and Related Carrying Charges

Month	Amount in Rates Deferred*	Cumulative Amount in Rates Deferred	Cumulative Deferred Revenue Requirement	Net Deferred Balance	Net of Tax	Pre-Tax WACC	Deferred Carrying Charges	
1	8,333	8,333	(15,677)	(7,344)	(5,425)	0.72%	(19)	
2	8,333	16,666	(31,264)	(14,598)	(10,783)	0.72%	(58)	
3	8,333	24,999	(46,762)	(21,763)	(16,075)	0.72%	(96)	
4	8,333	33,332	(62,170)	(28,838)	(21,301)	0.72%	(134)	
5	8,333	41,665	(77,489)	(35,824)	(26,461)	0.72%	(171)	
6	8,333	49,998	(92,718)	(42,720)	(31,555)	0.72%	(208)	
7	8,333	58,331	(107,858)	(49,527)	(36,583)	0.72%	(244)	
8	8,333	66,664	(122,908)	(56,244)	(41,545)	0.72%	(280)	
9	8,333	74,997	(137,869)	(62,872)	(46,440)	0.72%	(315)	
10	8,333	83,330	(152,740)	(69,410)	(51,270)	0.72%	(350)	
11	8,333	91,663	(167,522)	(75,859)	(56,033)	0.72%	(384)	
12	8,329	99,992	(182,214)	(82,222)	(60,733)	0.72%	(418)	
13	12,500	112,492	(196,866)	(84,374)	(62,323)	0.73%	(451)	
14	12,500	124,992	(211,426)	(86,434)	(63,844)	0.73%	(462)	
15	12,500	137,492	(225,895)	(88,403)	(65,299)	0.73%	(473)	
16	12,500	149,992	(240,272)	(90,280)	(66,685)	0.73%	(483)	
17	12,500	162,492	(254,557)	(92,065)	(68,004)	0.73%	(493)	
18	12,500	174,992	(268,751)	(93,759)	(69,255)	0.73%	(503)	
19	12,500	187,492	(282,853)	(95,361)	(70,438)	0.73%	(512)	
20	12,500	199,992	(296,864)	(96,872)	(71,555)	0.73%	(520)	
21	12,500	212,492	(310,783)	(98,291)	(72,603)	0.73%	(528)	
22	12,500	224,992	(324,611)	(99,619)	(73,584)	0.73%	(535)	
23	12,500	237,492	(338,347)	(100,855)	(74,497)	0.73%	(542)	
24	12,505	249,997	(351,992)	(101,995)	(75,339)	0.73%	(549)	
25	16,667	266,664	(365,543)	(98,879)	(73,037)	0.73%	(542)	
26	16,667	283,331	(379,002)	(95,671)	(70,667)	0.73%	(525)	
27	16,667	299,998	(392,370)	(92,372)	(68,231)	0.73%	(508)	
28	16,667	316,665	(405,647)	(88,982)	(65,727)	0.73%	(490)	
29	16,667	333,332	(418,832)	(85,500)	(63,155)	0.73%	(471)	
30	16,667	349,999	(431,926)	(81,927)	(60,515)	0.73%	(452)	
31	16,667	366,666	(444,928)	(78,262)	(57,808)	0.73%	(432)	
32	16,667	383,333	(457,839)	(74,506)	(55,034)	0.73%	(412)	
33	16,667	400,000	(470,659)	(70,659)	(52,192)	0.73%	(392)	
34	16,667	416,667	(483,387)	(66,720)	(49,283)	0.73%	(371)	
35	16,667	433,334	(496,024)	(62,690)	(46,306)	0.73%	(349)	
36	16,666	450,000	(508,570)	(58,570)	(43,263)	0.73%	(327)	
	450,000			(58,570)			(13,999)	(72,569) Net Owed to Customers

Appendix F, Schedule 2
Sheet 2 of 2
CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CASES 24-E-0461 and 24-G-0462
EXAMPLE OF DEFERRAL FOR CLOUD BASED SOFTWARE (EXPENSE) (ILLUSTRATIVE ONLY)

Assumptions:

1,000,000	IT Investment - Cloud Based Software
36	Assumed amortization period in rates (3 Years)
333,333	Annual Depreciation In Rates
	Assumed accounting treatment requires expense rather than capital treatment
1,000,000	Actual Expense in Year Purchased - Deferred
1,000,000	Adjustment to Net Plant Target

Adjustment to Net Plant Target

		AVERAGE NET UTILITY PLANT									
Month	Adjustment to Net Plant Target	Reserve @ BOM	Book Depreciation	Reserve @ EOM	Average Reserve	Average Net Plant	Pre-Tax WACC	Pre-Tax Return on Investment	Book Depreciation Expense	Revenue Requirement	Cumulative Revenue Requirement
1	1,000,000	0	27,778	27,778	13,889	986,111	0.72%	7,059	27,778	34,837	34,837
2			27,778	55,556	41,667	958,333	0.72%	6,860	27,778	34,638	69,475
3			27,778	83,334	69,445	930,555	0.72%	6,661	27,778	34,439	103,914
4			27,778	111,112	97,223	902,777	0.72%	6,462	27,778	34,240	138,154
5			27,778	138,890	125,001	874,999	0.72%	6,264	27,778	34,042	172,196
6			27,778	166,668	152,779	847,221	0.72%	6,065	27,778	33,843	206,039
7			27,778	194,446	180,557	819,443	0.72%	5,866	27,778	33,644	239,683
8			27,778	222,224	208,335	791,665	0.72%	5,667	27,778	33,445	273,128
9			27,778	250,002	236,113	763,887	0.72%	5,468	27,778	33,246	306,374
10			27,778	277,780	263,891	736,109	0.72%	5,269	27,778	33,047	339,421
11			27,778	305,558	291,669	708,331	0.72%	5,070	27,778	32,848	372,269
12			27,778	333,336	319,447	680,553	0.72%	4,872	27,778	32,650	404,919
13			27,778	361,114	347,225	652,775	0.73%	4,782	27,778	32,560	437,479
14			27,778	388,892	375,003	624,997	0.73%	4,578	27,778	32,356	469,835
15			27,778	416,670	402,781	597,219	0.73%	4,375	27,778	32,153	501,988
16			27,778	444,448	430,559	569,441	0.73%	4,171	27,778	31,949	533,937
17			27,778	472,226	458,337	541,663	0.73%	3,968	27,778	31,746	565,683
18			27,778	500,004	486,115	513,885	0.73%	3,764	27,778	31,542	597,225
19			27,778	527,782	513,893	486,107	0.73%	3,561	27,778	31,339	628,564
20			27,778	555,560	541,671	458,329	0.73%	3,357	27,778	31,135	659,699
21			27,778	583,338	569,449	430,551	0.73%	3,154	27,778	30,932	690,631
22			27,778	611,116	597,227	402,773	0.73%	2,950	27,778	30,728	721,359
23			27,778	638,894	625,005	374,995	0.73%	2,747	27,778	30,525	751,884
24			27,778	666,672	652,783	347,217	0.73%	2,543	27,778	30,321	782,205
25			27,778	694,450	680,561	319,439	0.73%	2,335	27,778	30,113	812,318
26			27,778	722,228	708,339	291,661	0.73%	2,132	27,778	29,910	842,228
27			27,778	750,006	736,117	263,883	0.73%	1,929	27,778	29,707	871,935
28			27,778	777,784	763,895	236,105	0.73%	1,726	27,778	29,504	901,439
29			27,778	805,562	791,673	208,327	0.73%	1,523	27,778	29,301	930,740
30			27,778	833,340	819,451	180,549	0.73%	1,320	27,778	29,098	959,838
31			27,778	861,118	847,229	152,771	0.73%	1,117	27,778	28,895	988,733
32			27,778	888,896	875,007	124,993	0.73%	913	27,778	28,691	1,017,424
33			27,778	916,674	902,785	97,215	0.73%	710	27,778	28,488	1,045,912
34			27,778	944,452	930,563	69,437	0.73%	507	27,778	28,285	1,074,197
35			27,778	972,230	958,341	41,659	0.73%	304	27,778	28,082	1,102,279
36			27,770	1,000,000	986,115	13,885	0.73%	101	27,770	27,871	1,130,150
			1,000,000							1,130,150	

Deferral and Related Carrying Charges

Month	Deferred Expense	Amount in Rates	Net Deferred Expense Balance	Net of Tax	Pre-Tax WACC	Deferred Carrying Charges	
1	1,000,000	(34,837)	965,163	712,918	0.72%	2,552	
2	1,000,000	(69,475)	930,525	687,332	0.72%	5,012	
3	1,000,000	(103,914)	896,086	661,894	0.72%	4,829	
4	1,000,000	(138,154)	861,846	636,603	0.72%	4,648	
5	1,000,000	(172,196)	827,804	611,457	0.72%	4,467	
6	1,000,000	(206,039)	793,961	586,459	0.72%	4,288	
7	1,000,000	(239,683)	760,317	561,608	0.72%	4,109	
8	1,000,000	(273,128)	726,872	536,904	0.72%	3,932	
9	1,000,000	(306,374)	693,626	512,347	0.72%	3,755	
10	1,000,000	(339,421)	660,579	487,937	0.72%	3,580	
11	1,000,000	(372,269)	627,731	463,674	0.72%	3,406	
12	1,000,000	(404,919)	595,081	439,557	0.72%	3,233	
13	1,000,000	(437,479)	562,521	415,506	0.73%	3,132	
14	1,000,000	(469,835)	530,165	391,606	0.73%	2,956	
15	1,000,000	(501,988)	498,012	367,857	0.73%	2,782	
16	1,000,000	(533,937)	466,063	344,257	0.73%	2,608	
17	1,000,000	(565,683)	434,317	320,808	0.73%	2,436	
18	1,000,000	(597,225)	402,775	297,510	0.73%	2,265	
19	1,000,000	(628,564)	371,436	274,361	0.73%	2,094	
20	1,000,000	(659,699)	340,301	251,363	0.73%	1,925	
21	1,000,000	(690,631)	309,369	228,515	0.73%	1,758	
22	1,000,000	(721,359)	278,641	205,818	0.73%	1,591	
23	1,000,000	(751,884)	248,116	183,271	0.73%	1,425	
24	1,000,000	(782,205)	217,795	160,874	0.73%	1,260	
25	1,000,000	(812,318)	187,682	138,631	0.73%	1,094	
26	1,000,000	(842,228)	157,772	116,538	0.73%	932	
27	1,000,000	(871,935)	128,065	94,595	0.73%	772	
28	1,000,000	(901,439)	98,561	72,802	0.73%	612	
29	1,000,000	(930,740)	69,260	51,159	0.73%	453	
30	1,000,000	(959,838)	40,162	29,666	0.73%	295	
31	1,000,000	(988,733)	11,267	8,322	0.73%	139	
32	1,000,000	(1,017,424)	(17,424)	(12,870)	0.73%	(17)	
33	1,000,000	(1,045,912)	(45,912)	(33,913)	0.73%	(171)	
34	1,000,000	(1,074,197)	(74,197)	(54,806)	0.73%	(324)	
35	1,000,000	(1,102,279)	(102,279)	(75,548)	0.73%	(476)	
36	1,000,000	(1,130,150)	(130,150)	(96,135)	0.73%	(627)	
			(130,150)			76,725	(53,425) Net Owed to Customers

Appendix F, Schedule 3

Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462
Example Calculation of Distribution ROW Maintenance Deferral (Illustrative Only)
($000)

Example 1, Net Underspend:

	Distribution			Cumulative
	RY1	**RY2**	**RY3**	**Total**
Allowance ($000) Per Appendix A	26,300	26,300	26,300	78,900
Actual Spend (For Illustrative Purposes Only)	25,000	27,000	25,300	77,300
CUMULATIVE OVER/(UNDER) SPEND				**(1,600)**
CUMULATIVE $ TO RETURN TO CUSTOMER AT END OF RATE YEAR 3				**(1,600)**

Example 2, Net Overspend:

	Distribution			Cumulative
	RY1	**RY2**	**RY3**	**Total**
Allowance ($000) Per Appendix A	26,300	26,300	26,300	78,900
Actual Spend (For Illustrative Purposes Only)	26,000	27,000	28,000	81,000
CUMULATIVE OVER/(UNDER) SPEND				**2,100**
CUMULATIVE $ TO RETURN TO CUSTOMER AT END OF RATE YEAR 3				**-**

Appendix F, Schedule 4

Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462
Example Calculation of Call Center Legislation Deferral (Illustrative Only)
($000)

		Electric			Gas		
		RY1	**RY2**	**RY3**	**RY1**	**RY2**	**RY3**
Allowance for Call Center Overflow ($000)*		1,802	1,474	1,159	450	368	290
RY1 Rate Allowance		1,802			450		
Actual Spend (For Illustrative Purposes Only)	7,000	5,600			1,400		
Incremental Spending		3,798			950		
Tier 1 - Deferral Cap[1]	7,500	6,000			1,500		
Incremental Expense in excess of Tier 1 Cap		-			-		
Total Deferred (RY1)		3,798			950		
Incremental Expense paid by shareholders		-			-		
RY2 Rate Allowance			1,474			368	
Actual Spend (For Illustrative Purposes Only)	10,000		8,000			2,000	
Incremental Spending			6,526			1,632	
Tier 1 - Deferral Cap[1]	7,500		6,000			1,500	
Incremental Expense in excess of Tier 1 Cap			526			132	
Tier 2 - Deferral Cap[2]	1,000		800			200	
@ 50% Sharing [2]			263			66	
Incremental Expense in excess of Tier 2 Cap			-			-	
Total Deferred (RY2)			6,263			1,566	
Incremental Expense paid by shareholders			263			66	
RY3 Rate Allowance				1,159			290
Actual Spend (For Illustrative Purposes Only)	11,000			8,800			2,200
Incremental Spending				7,641			1,910
Tier 1 - Deferral Cap[1]	7,500			6,000			1,500
Incremental Expense in excess of Tier 1 Cap				1,641			410
Tier 2 - Deferral Cap[2]	1,000			800			200
@ 50% Sharing [2]				400			100
Total Deferred (RY3)				6,400			1,600
Incremental Expense paid by shareholders				1,241			310

*In Appendix A, this rate allowance is included within *Meter Reading, Collections & Call Volume Overflow.*

[1] The Company is authorized to defer 100% of incremental expenditures up to $7.5M per Rate Year

[2] The Company is authorized to defer 50% of incremental expenditures between $7.5M - $8.5M per Rate Year

Appendix F, Schedule 5
Sheet 1 of 2
Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462
Example Calculation of Non-Major Storm Deferral (Net Underspend) (Illustrative Only)
($000)

	RY1	RY2	RY3	Cumulative Deferral
Allowance ($000) Per Appendix A	7,535	7,701	7,870	
RY1 Allowance	7,535			
Actual Spend (For Illustrative Purposes Only)	6,200			
(Under) / Over Spend	(1,335)			(1,335)
RY2 Allowance		7,701		
Actual Spend (For Illustrative Purposes Only)		8,500		
(Under) / Over Spend		799		(536)
RY3 Allowance			7,870	
Actual Spend (For Illustrative Purposes Only)			7,000	
(Under) / Over Spend			(870)	(1,406)
CUMULATIVE $ TO RETURN TO CUSTOMER AT END OF RATE YEAR 3			**(1,406)**	

Appendix F, Schedule 5
Sheet 2 of 2
Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462
Example Calculation of Non-Major Storm Deferral (Net Overspend) (Illustrative Only)
($000)

	RY1	RY2	RY3	Cumulative Deferral
Allowance ($000) Per Appendix A	7,535	7,701	7,870	
RY1 Allowance	7,535			
Actual Spend (For Illustrative Purposes Only)	8,000			
(Under) / Over Spend	465			-
RY2 Allowance		7,701		
Actual Spend (For Illustrative Purposes Only)		7,000		
(Under) / Over Spend		(701)		(236)
RY3 Allowance			7,870	
Actual Spend (For Illustrative Purposes Only)			10,000	
(Under) / Over Spend			2,130	-
CUMULATIVE $ TO BE ABSORBED BY COMPANY AT END OF RATE YEAR 3			**1,894**	

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Major Storm Reserve and Non-Major Storm Events

Major Storm Reserve

Major Storm Reserve Funding

To the extent that the Company incurs incremental major storm damage costs in excess of the amount accrued in the Major Storm Reserve over the term of the Rate Plan, the Company will defer expenses for the future recovery from customers, and the rate allowance for the Major Storm Reserve will be adjusted accordingly during the Company's next rate proceeding. To the extent that the Company incurs major storm damage expenses less than the amount accrued in the Major Storm Reserve over the Rate Year, the Company will defer the variation to serve as a credit toward future major storm events. The reserve balance, whether a debit balance or credit balance, will accrue carrying charges at the Company's pre-tax rate of return.

Costs Chargeable to the Major Storm Reserve

A major storm event is defined as a period of adverse weather during which service interruptions affect at least 10 percent of customers in an operating area and/or result in customers being without electric service for durations of at least 24 hours (16 NYCRR §97.1[c]). Except as otherwise provided herein, once an event meets the definition of a major storm event, incremental restoration costs incurred as a result of the event must reach a level of at least $500,000, in order for expenses related to the adverse weather event to be chargeable to the major storm reserve.

Specifically, the following types of incremental restoration costs are authorized to be charged to the major storm reserve: incremental labor and the applicable payroll taxes and incremental accounts payable. Incremental labor is overtime paid to union and management employees in conjunction with the storm event. Incremental accounts payable includes, but is not limited to, tree trimming, mutual aid, other contractor/temp employees, communication (excluding communication costs for cell phone usage), dry ice, water, lodging, food, miscellaneous employee expenses, transportation expenses that do not originate from the Company, and materials and supplies costs that Central Hudson would not have incurred, except for the major storm event.

The Company can charge costs against the Major Storm Reserve for restoration activity for a period up to 10 days following the date on which the Company is able to serve all customers. If Central Hudson incurs incremental expenses more than 10 days following restoration of the ability to serve all customers, Central Hudson has the right to petition the Commission for authorization to charge these costs to the Major Storm Reserve, and the petition will not be subject to the Commission's traditional three-part deferral test.

Any proceeds or reimbursements from insurance, the Federal Emergency Management Agency, New York State or any other reimbursement or proceeds received to cover such costs will be deducted from expenses charged to the Major Storm Reserve.

In addition, the Company is authorized to charge the major storm reserve for payments made in the form of retainers to mutual aid crews in order to allow Central Hudson to more readily secure aid when storm events require such prudent action. Central Hudson shall submit such retainer contracts to the Secretary in Case 24-E-0461 within 30 days of any changes or new contracts, but not less than once per calendar year.

Pre-Staging & Mobilization Events

Central Hudson is authorized to charge the major storm reserve for pre-staging and mobilization costs incurred in reasonable anticipation that a storm will affect its electric operations to the degree of meeting the criteria of a major storm, but which ultimately does not do so. The following incremental costs can be charged: contractors and/or utility companies providing mutual assistance, employee labor, meals, lodging, and mutual aid travel to and from Central Hudson.

Incremental costs per pre-staging event will be charged as follows:

$1 to $100,000	Expense
$100,000 to $1.75M	Charged to Reserve
Over $1.75M	85% to Reserve/15% to Expense

Central Hudson can file a petition requesting to defer the portion charged to expense (15%) of prestaging and mobilization costs in excess of $1.75M per event, and it will be subject to the Commission’s three-part test to determine if deferral accounting treatment should be granted. Any amounts not chargeable to the major storm reserve will be charged to a separate non-major storm expense (O&M expense) function number for tracking purposes. Any charges to this function number during the month will be supported with documentation from operations related to the event tracked which did not qualify as chargeable to the Major Storm Reserve.

Documentation and Review

Central Hudson will report the costs for each major storm on a separate work order. The Company will file data demonstrating that the adverse weather event qualified as a major storm and documentation of the storm costs for audit to the Office of Accounting, Audits and Finance within 120 days of the date on which the Company is able to serve all customers. The documentation will identify costs broken out into major expense categories and capital. Central Hudson shall also provide quantification of the number of full-time equivalents used in storm restoration and/or preparation, including internal employees, external contractors and mutual assistance.

All costs charged to the Major Storm Reserve are subject to audit by Staff. Staff will review documented costs and communicate any concerns to the Company within a reasonable period of receipt of storm cost documentation from the Company. Such communication will not limit Staff's further review.

Consistent with current practice, Staff will continue to allow the inclusion of estimated costs in the Company's storm cost documentation that will be filed within 120 days of the date on which the Company is able to serve all customers. As such, to the extent that final invoices are not received within the 120-day initial filing notice, the Company will provide Staff final bills upon receipt, and costs charged to the Major Storm Reserve will be adjusted accordingly.

Non-Major Storm Events

Non-Major Storm Expense Definition – Costs incurred for restoration of outages caused by any adverse weather event that does not meet the criteria of a major storm.

Costs recorded as non-major storm expense include employee labor and applicable overheads; accounts payable, including but not limited to, tree trimming, other contractor expenses, and miscellaneous employee expenses; transportation expenses; and materials and supplies costs. Additionally, in accordance with the provisions of the major storm reserve, applicable pre-staging costs not eligible to be charged to the major storm reserve will be charged to non-major storm expense. Any capitalized costs are excluded, and proceeds from insurance, the Federal Emergency Management Agency, New York State or any other reimbursement or proceeds received to cover such costs will offset the costs incurred.

Costs recorded as non-major storm expense will be subject to audit by DPS Staff.

Non-Major Storm Reporting

Within 45 days after the end of each quarterly period, the Company shall file a report to the Secretary for the preceding quarter with all costs incurred in the Non-Major Storm Expense Account. These costs will be detailed based on one of three types of costs incurred: (1) Class 1 or greater weather events, (2) weather events less severe than a Class 1 event, and (3) the portion of pre-staging costs charged to non-major storm expense per the Pre-Staging and Mobilization provisions of the Major Storm Reserve.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Major Storm Reserve and Non-Major Storm Events

For events that the Company is able to specifically track, which at a minimum includes Class 1 weather events or greater, the event and cost details will follow the event level template as provided in Appendix M, Schedule A. For all other non-major storm expenses, cost details will be provided by class of entry (i.e., labor, accounts payable, materials and supplies, etc.). The portion of pre-staging costs charged to non-major storm expense per the Pre-Staging and Mobilization provisions of the Major Storm Reserve will be provided by the Company by event date.

Additionally, for events that the Company is able to specifically track, the report will also segregate expenses into two categories (proactive and reactive). Storm expenses for proactive storm events will include circumstances where the Company forecasted the need for advanced preparation of crews and support personnel (i.e., contact center staffing) and captured data related to the adverse weather and restoration preparation efforts. Storm expenses for reactive storm events will include circumstances where the forecast did not warrant formal advanced preparation efforts, but interruptions nevertheless occurred, and restoration efforts were required due to adverse weather conditions. An example of this report format is provided in Appendix M, Schedule A.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Rate Adjustment Mechanism

The Company will implement a Rate Adjustment Mechanism ("RAM") to refund or recover the net balance of RAM Eligible Deferrals and Carrying Charges as identified in the following listing, subject to the dollar thresholds shown in the table below. All RAM revenues and deferrals are subject to reconciliation as explained in further detail in the body of this text.

RAM Eligible Deferrals and Costs include:

(1) All Commission approved carrying charges;

(2) Deferred revenues related to Finance Charges and Reconnection Fees;

(3) PRAs and unencumbered NRAs earned or incurred and deferred for future recovery or pass-back for achieving/failing targets or objectives defined;

(4) Uncollectible write-offs and collection agency fee deferral balances;

(5) Major storm events charged to the Major Storm Reserve in excess of the rate allowance;

Recovery Mechanics

The Company shall measure the deferred regulatory asset and liability balances for the items specified as RAM Eligible Deferrals and Costs as of December 31 of each year beginning in 2025. The electric and gas RAM balances identified for recovery / return shall be subject to the minimum and maximum amounts shown in the table below and shall be identified in respective RAM Compliance Filings. The RAM for Electric and Gas shall be identified in respective RAM Compliance Filings submitted by March 31 of each year and shall be implemented in rates on July 1 of each year for collection over the 12 months from July 1 to June 30.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Rate Adjustment Mechanism

	Electric ($million)		**Gas ($million)**	
	Dollar Threshold		Dollar Threshold	
	Minimum	Maximum*	Minimum	Maximum*
Rate Year 1	$0.350	$15.400	$0.150	$4.800
Rate Year 2	$0.350	$16.500	$0.150	$5.200
Rate Year 3	$0.350	$17.500	$0.150	$5.600

*Maximum threshold is calculated as 2.5% of total operating revenues, as provided in the Rate Year revenue requirement.

To the extent the service classification/sub-classification allocation of balances results in a zero factor for a service classification/sub-classification, such allocated balance will be considered an over/under-collection and treated accordingly.

The RAMs for Electric and Gas will be determined individually by netting the RAM Eligible Deferrals. Any net RAM Eligible Deferral value in excess of the specific Electric or Gas limit will remain deferred and accrue carrying charges in accordance with its source deferral authorization and will be included in the determination of RAM eligible balances in the subsequent year.

RAM Review Process

Upon request of a Signatory to this JP and within 60 days of the RAM filing, the Company will convene an informational meeting in person or via teleconference to review the Company's calculation of the RAM.

In the event that DPS Staff or any signatory to the JP objects to the calculation of the RAM, Staff or such signatory shall notify the Company and the parties in writing within 30 calendar days after the RAM Compliance Filing is submitted. The Company will, in turn, respond in writing within 30 calendar days addressing the objection. To the extent that Staff or the signatory believes its concerns were not fully addressed by the

Company's response, Staff or such signatory may submit written comments to the Commission.

In the event of an unresolved dispute regarding the calculation of the annual RAM, the RAM will be implemented as described above and any disputed amounts subject to refund will be incorporated in a subsequent reconciliation. The Signatories will use their best efforts to resolve disputes within 150 calendar days of the Company's response. The Signatories agree to utilize the Commission's dispute resolution process to resolve any contested matters. To the extent the Signatories are unable to resolve any remaining differences, the Signatories agree to present such differences to the Commission for resolution.

The implementation of the RAM shall not limit Staff's right to audit the deferred costs included by the Company in the RAM.

Carrying Costs

During the period the RAM is in effect, for those deferrals being specifically collected or returned, carrying costs will be based on the Commission's authorized Other Customer Capital Rate.

Over/under-collections or refund of RAM amounts will be carried forward to subsequent periods and assumed to be the first dollars collected or refunded. Deferred amounts will be allocated to Electric and Gas in accordance with the nature of the underlying item.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Rate Adjustment Mechanism

<u>Electric Recovery / Refund</u>

The Electric RAM annual recovery/return amounts shall be delivered through a component of the MISC. It will be allocated to service classes/sub-classes based on annual delivery service revenues. The rates will be developed on per-kWh basis for non-demand billed customers and per-kW basis for demand billed customers.

<u>Gas Recovery / Refund</u>

The Gas RAM annual recovery/return amounts shall be delivered through a component of the MISC. It will be allocated to service classes, excluding the interruptible service class, based on annual delivery service revenues. The rates will be developed on a per-Ccf basis.

Appendix H, Schedule A

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Illustrative Example of RAM Recovery Dollar Limitations

	RY1	RY2	RY2
ELECTRIC:			
Total Operating Revenues [1]	617,027	660,724	700,602
% Limitation	2.5%	2.5%	2.5%
Dollar Limitation (+/-)[3]	15,400	16,500	17,500
GAS:			
Total Operating Revenues [2]	193,609	207,179	223,872
% Limitation	2.5%	2.5%	2.5%
Dollar Limitation (+/-)[3]	4,800	5,200	5,600

[1] Appendix A, Schedule 1

[2] Appendix A, Schedule 2

[3] Surcharge/Surcredit limitation

Appendix H, Schedule B

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Illustrative Example of RAM Surcharge Assessment

Rate Adjustment Mechanism (RAM)
Eligible Deferrals & Costs
Balances as of 12/31/25
($ Thousands)

		Electric ($000)	Gas ($000)
1	RAM (Over)/Under Final True Up (7/1/2023 - 6/30/2024)	$ -	$ -
2	RAM (Over)/Under Estimated True Up (7/1/2024 - 6/30/2025)	-	-
3	Carrying Charges - Asset	7,000	500
4	Carrying Charges - Liability	(3,000)	(750)
5	Finance Charges & Reconnection Fees	(1,000)	(250)
6	Uncollectible Write-Offs & Collection Agency Fees	12,000	3,600
7	Positive Revenue Adjustments	-	-
8	Negative Revenue Adjustments	-	-
9	Major Storm Costs	6,000	-
10	Total RAM Eligible Deferrals	$ 21,000	$ 3,100
11	RAM Recovery / Return Minimum Threshold	$ 350	$ 150
12	Exceed Minimum Threshold - Yes/No	Yes	Yes
14	RAM Recovery / Return Maximum Threshold	$ 15,400	$ 4,800
15	Total to be Recovered/(Returned) via Ram (7/1/2026 - 6/30/2027)	$ 15,400	$ 3,100

Appendix H, Schedule C

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Illustrative Example of RAM Impacts
Effective July 1, 2026 at Maximum Threshold - Surcharge

Electric

Service Class	RY Delivery Service Revenue	RY Delivery Allocation %	RAM Eligible Deferrals	7/26-6/27 Est of Total Revenue[1]	Bill Impact
			$ 15,400,000		
1	$ 395,853,993	69.07%	$ 10,636,780	$ 629,802,647	1.7%
2 - ND	$ 37,721,131	6.58%	$ 1,013,320	$ 59,724,588	1.7%
2 - PD	$ 7,856,022	1.37%	$ 210,980	$ 34,563,307	0.6%
2 - SD	$ 96,881,557	16.90%	$ 2,602,600	$ 234,995,378	1.1%
3	$ 12,092,060	2.11%	$ 324,940	$ 42,132,117	0.8%
5	$ 2,962,490	0.52%	$ 80,080	$ 4,053,617	2.0%
6	$ 1,417,977	0.25%	$ 38,500	$ 3,964,213	1.0%
8	$ 6,208,907	1.08%	$ 166,320	$ 7,211,029	2.3%
9	$ 222,752	0.04%	$ 6,160	$ 267,320	2.3%
13 - S	$ 2,817,877	0.49%	$ 75,460	$ 13,611,519	0.6%
13 - T	$ 9,085,306	1.59%	$ 244,860	$ 66,859,948	0.4%
	$ 573,120,072	100.00%	$ 15,400,000	$ 1,097,185,683	1.4%

Gas

Service Class	RY Delivery Service Revenue	RY Delivery Allocation %	RAM Eligible Deferrals	7/26-6/27 Est of Total Revenue[1]	Bill Impact
			$ 4,800,000		
1, 12 & 16	$ 108,482,865	60.38%	$ 2,898,240	$ 145,272,947	2.0%
2, 6, 13 & 15	$ 65,250,688	36.32%	$ 1,743,360	$ 115,045,000	1.5%
11 - T	$ 1,589,068	0.88%	$ 42,240	$ 5,568,137	0.8%
11 - D	$ 2,766,975	1.54%	$ 73,920	$ 5,416,374	1.4%
11 - D Large Mains	$ 1,572,249	0.88%	$ 42,240	$ 4,781,535	0.9%
	$ 179,661,844	100.00%	$ 4,800,000	$ 276,083,994	1.7%

[1] Estimated based on Calendar Year 2023 commodity and surcharge revenue, inclusive of estimate of ESCO supply and proposed RYE 6/2026 delivery revenues

Appendix H, Schedule C

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Illustrative Example of RAM Impacts
Effective July 1, 2026 at Maximum Threshold - Surcharge

Electric

Service Class	RY Delivery Service Revenue	RY Delivery Allocation %	RAM Eligible Deferrals	7/26-6/27 Est of Total Revenue[1]	Bill Impact
			$ (15,400,000)		
1	$ 395,853,993	69.07%	$ (10,636,780)	$ 629,802,647	-1.7%
2 - ND	$ 37,721,131	6.58%	$ (1,013,320)	$ 59,724,588	-1.7%
2 - PD	$ 7,856,022	1.37%	$ (210,980)	$ 34,563,307	-0.6%
2 - SD	$ 96,881,557	16.90%	$ (2,602,600)	$ 234,995,378	-1.1%
3	$ 12,092,060	2.11%	$ (324,940)	$ 42,132,117	-0.8%
5	$ 2,962,490	0.52%	$ (80,080)	$ 4,053,617	-2.0%
6	$ 1,417,977	0.25%	$ (38,500)	$ 3,964,213	-1.0%
8	$ 6,208,907	1.08%	$ (166,320)	$ 7,211,029	-2.3%
9	$ 222,752	0.04%	$ (6,160)	$ 267,320	-2.3%
13 - S	$ 2,817,877	0.49%	$ (75,460)	$ 13,611,519	-0.6%
13 - T	$ 9,085,306	1.59%	$ (244,860)	$ 66,859,948	-0.4%
	$ 573,120,072	100.00%	$ (15,400,000)	$ 1,097,185,683	-1.4%

Gas

Service Class	RY Delivery Service Revenue	RY Delivery Allocation %	RAM Eligible Deferrals	7/26-6/27 Est of Total Revenue[1]	Bill Impact
			$ (4,800,000)		
1, 12 & 16	$ 113,002,953	59.90%	$ (2,875,200)	$ 145,272,947	-2.0%
2, 6, 13 & 15	$ 69,552,992	36.87%	$ (1,769,760)	$ 115,045,000	-1.5%
11 - T	$ 1,641,107	0.87%	$ (41,760)	$ 5,568,137	-0.7%
11 - D	$ 2,888,282	1.53%	$ (73,440)	$ 5,416,374	-1.4%
11 - D Large Mains	$ 1,583,014	0.84%	$ (40,320)	$ 4,781,535	-0.8%
	$ 188,668,349	100.01%	$ (4,800,480)	$ 276,083,994	-1.7%

[1] Estimated based on Calendar Year 2023 commodity and surcharge revenue, inclusive of estimate of ESCO supply and proposed RYE 6/2026 delivery revenues

Appendix I

Central Hudson Gas & Electric Corporation
Case Nos. 24-E-0461 & 24-G-0462
Net Deferred Accounts Available For Moderation

The following accounts are subject to offset at the time of the Commission's Order. The balances used for offset will be as of July 1, 2025, with the net deferred regulatory credit available for rate moderation:

Description	Electric	Gas
Carrying Charges - CDGM Consolidated Billing	X	N/A
Carrying Charges - Climate Change Resiliency Plan	X	N/A
Carrying Charges - Collect Costs for Asbestos Litigation	X	N/A
Carrying Charges - COVID Lost Revenue	X	N/A
Carrying Charges - DEI Order 22-M-0314	X	X
Carrying Charges - Economic Development	X	N/A
Carrying Charges - Electric Vehicles Time of Use	X	N/A
Carrying Charges - Energy Affordability Program	X	X
Carrying Charges - Energy Efficiency	X	X
Carrying Charges - Environmental SIR Costs & Recovery	X	X
Carrying Charges - Finance Charges	X	N/A
Carrying Charges - Gas Non Pipe Alternative	N/A	X
Carrying Charges - IEDR	X	X
Carrying Charges - Major Storm Reserve	X	N/A
Carrying Charges - OPEB (Over) / Under Collection	X	X
Carrying Charges - Payment by Credit Card Overcollection	X	X
Carrying Charges - Pension Plan (Over) / Under Collection	X	X
Carrying Charges - RAM	X	X
Carrying Charges - Rate Moderator Balance	X	X
Carrying Charges - REV Demonstration Projects	X	N/A
Carrying Charges - Sales Tax Refund	X	X
Carrying Charges - Stray Voltage Undercollection	X	N/A
Carrying Charges - TDM and DLM Programs	X	N/A
Carrying Charges - Uncollectible Write Offs	X	X
Carrying Charges - Variable Rate Interest	X	X
Climate Change Resiliency Plan	X	N/A
Collect Costs for Asbestos Litigation	X	N/A
COVID Lost Revenues	X	N/A
DEI Order 22-M-0314	X	X
Economic Development	X	N/A
Electric Vehicles Time of Use	X	N/A
Finance Charges	X	N/A
Gas Safety Final Ruling	N/A	X
IEDR Phase 1	X	X
Negative Revenue Adjustments	X	X
NPA Incentive	N/A	X
OPEB (Over) / Under Collection	X	X
Payment by Credit Card Overcollection	X	X
Pension Plan (Over) / Under Collection	X	X
Positive Revenue Adjustment	N/A	X
Rate Adjustment Mechanism	X	X
Rate Moderator Balance	X	X
Research & Development	X	X
REV Demonstration Projects	X	N/A
Sales Tax Refund	X	X
Stray Voltage	X	N/A
Uncollectible Write Offs	X	X
Variable Rate Interest Undercollection	X	X

This listing of accounts is presented without prejudice with respect to any error or omission and the Company or Staff reserves the right to revise this listing, which will be subject to Staff review and approval.

Appendix J

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Revenue Matching Factors

ELECTRIC:	Rate Year #1	Rate Year #2	Rate Year #3
Research & Development:			
Rate Allowance ($000)	$4,292	$4,386	$4,482
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	5,185,417	5,273,299	5,390,727
Revenue Matching Factor - $/kWh	$0.000828	$0.000832	$0.000831
Pension Plan:			
Rate Allowance ($000)	($20,351)	($19,328)	($18,192)
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	5,185,417	5,273,299	5,390,727
Revenue Matching Factor - $/kWh	($0.003925)	($0.003665)	($0.003375)
OPEB - Including Medicare Subsidy			
Rate Allowance ($000)	($7,625)	($7,403)	($6,912)
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	5,185,417	5,273,299	5,390,727
Revenue Matching Factor - $/kWh	($0.001470)	($0.001404)	($0.001282)

GAS:	Rate Year #1	Rate Year #2	Rate Year #3
Research & Development:			
Rate Allowance ($000)	$911	$931	$951
SC 1, 2, 6, 12 & 13 Sales (Mcf)	13,415,407	13,307,521	13,218,440
Revenue Matching Factor - $/Mcf	$0.067907	$0.069960	$0.071945
Pension Plan:			
Rate Allowance ($000)	($5,787)	($5,496)	($5,173)
SC 1, 2, 6, 12 & 13 Sales (Mcf)	13,415,407	13,307,521	13,218,440
Revenue Matching Factor - $/Mcf	($0.431370)	($0.413000)	($0.391347)
OPEB - Including Medicare Subsidy			
Rate Allowance ($000)	($2,168)	($2,105)	($1,965)
SC 1, 2, 6, 12 & 13 Sales (Mcf)	13,415,407	13,307,521	13,218,440
Revenue Matching Factor - $/Mcf	($0.161605)	($0.158181)	($0.148656)

Appendix K Sheet 1 of 3

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Depreciation Factors and Rates

Effective as of 7/1/24

ELECTRIC

Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate
HYDRO PRODUCTION					
331-00-1	STRUCTURES & IMPROVEMENTS	95	R2	-50	0.0158
332-00-1	RESERVOIRS, DAMS	95	R3	-60	0.0168
333-00-1	TURBINES & GENERATORS	85	R2	-60	0.0188
334-10-1	ACCESSORY ELEC. EQUIP.	55	R1	-25	0.0227
335-00-1	MISC. POWER PLANT EQUIP.	55	S1.5	-20	0.0218
OTHER PRODUCTION					
341-00-1	STRUCTURES AND IMPROVEMENTS	45	R2	-10	0.0244
342-00-1	FUEL HOLDERS, PRODUCERS & ACCESSORIES	45	S0.5	-20	0.0267
343-00-1	PRIME MOVERS	25	R4	-10	0.0440
344-00-1	GENERATORS	30	R4	-15	0.0383
345-00-1	ACCESSORY ELECTRIC EQUIPMENT	30	R1.5	-20	0.0400
346-00-1	MISCELLANEOUS POWER PLANT EQUIPMENT	30	S5	0	0.0333
TRANSMISSION					
350-11&15-1	LAND & LAND RIGHTS	85	R4	0	0.0118
350-13-1	LAND & LAND RIGHTS SUBSTATIONS	85	R4	0	0.0118
352-00-1	STRUCTURES & IMPROVEMENTS	80	R3	-30	0.0163
353-11	STATION EQUIPMENT	53	R1.5	-20	0.0226
353-12-1	SUPERVISORY EQUIPMENT- IN USE	33	L1.5	-20	0.0364
353-20-1	SUPERVISORY EQUIPMENT- HELD	45	S0.5	-20	0.0267
353-30-1	STATION EQUIP-ELECTRONIC	30	S2	-20	0.0400
354-00-1	TOWERS & FIXTURES	80	R3	-30	0.0163
355-00, 10 &15-1	POLES & FIXTURES	55	R2	-70	0.0309
356-10-1	OVERHEAD COND. & DEVICES	70	R2	-60	0.0229
356-15-1	OVERHEAD COND. & DEV. 345KV	70	R2	-60	0.0229
356-20&25-1	OVERHEAD LINES, CLEARING	75	R3	-60	0.0213
357-00-1	UNDERGROUND CONDUIT	41	R0.5	0	0.0244
358-00-1	UNERGROUND COND. & DEVICES	60	R3	-15	0.0192
DISTRIBUTION					
360-11&22-1	LAND & LAND RIGHTS - OH	75	S4	0	0.0133
360-13 & 23-1	LAND & LAND RIGHTS - SUB & UND	75	S4	0	0.0133
361-00-1	STRUCTURES & IMPROVEMENTS	75	R3	-30	0.0173
362-11-1	STATION EQUIPMENT-IN USE	54	S0.5	-30	0.0241
362-12-1	SUPERVISORY EQUIPMENT	30	S0.5	-25	0.0417
362-20-1	STATION EQUIPMENT-HELD	45	S1.5	-30	0.0289
362-30-1	STATION EQUIP-ELECTRONICS	20	S2	-30	0.0650
364-00-1	POLES & FIXTURES	55	R0.5	-50	0.0273
365-10&20-1	OVHD. CONDUCTORS & DEVICES	65	R0.5	-50	0.0231
366-11&22-1	UNDERGROUND CONDUIT	80	R3	-55	0.0194
367-00-1	UNDERGROUND COND. & DEVICES	70	R3	-40	0.0200
368-00-1	TRANSFORMERS	42	R1	-20	0.0286
369-10-1	OVERHEAD SERVICES	65	R2	-100	0.0308
*369-21&22-1	UNDERGROUND SERVICES	65	R2	-40	0.0215
370-11&20-1	METERS & INSTALLATION	34	L0	0	0.0294
371-00-1	INSTALLATION ON CUST. PREMISES	25	R0.5	-30	0.0520
372-10-1	LEASED PROP. ON CUST. PREMISES	8	L2	0	0.1250
373-00-1	STREET LIGHTS & CONDUCTORS	30	O1	-15	0.0383
GENERAL PLANT					
390-00-1	STRUCTURES AND IMPROVEMENTS	45	R0.5	-30	0.0289

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Depreciation Factors and Rates

Effective as of 7/1/24

GAS

Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate
TRANSMISSION					
365-11&20-2	LAND & LAND RIGHTS	70	R4	0	0.0143
366-20-2	STRUCTURES & IMPROVEMENTS	55	S1	-25	0.0227
367-00-2	MAINS	80	R4	-50	0.0188
369-11-2	STATION EQUIPMENT	35	L1	-20	0.0343
369-12-2	SUPERVISORY EQUIPMENT	22	L2	-20	0.0545
369-30-2	SUPERVISORY EQUIPMENT - ELECTRONIC	25	S2	-20	0.0480
DISTRIBUTION					
374-11 & 13-2	LAND & LAND RIGHTS	75	R3	0	0.0133
375-00-2	STRUCTURES & IMPROVEMENTS	65	S1.5	-40	0.0215
376-00-&11, 12,13-2	MAINS	83	R2	-60	0.0193
378-11-2	STATION EQUIPMENT	37	L0.5	-40	0.0378
378-12-2	SUPERVISORY EQUIPMENT	35	S0	-40	0.0400
378-30-2	STATION EQUIP - ELECTRONIC	28	S2	-40	0.0500
380-00-2	SERVICES	75	R1.5	-100	0.0267
381-00-2	METERS	24	L1	0	0.0417
382-00-2	METER INSTALLATIONS	24	L1	0	0.0417
385-00-2	INDUSTRIAL-STATION EQUIPMENT	45	R2.5	-30	0.0289
385-10-2	INDUSTRIAL-STATION EQUIPMENT	45	R4	-30	0.0289

IROQUOIS TRANSMISSION

Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate
365-50-2 ASL	LAND & LAND RIGHTS	70	R4	0	0.0143
365-50-2 RL	LAND & LAND RIGHTS- **original cost only fully amortized 12/31/2007**			0	0.0000
366-50-2 ASL	STRUCTURES & IMPROVEMENTS	55	S1	-25	0.0227
366-50-2 RL	STRUCTURES & IMPROVEMENTS- **original cost only fully amortized**			-55	0.0110
367-50-2 ASL	MAINS	80	R3	-25	0.0156
367-50-2 RL	MAINS- **original cost only fully amortized**			-25	0.0031
369-51-2 ASL	STATION EQUIPMENT	35	L1	-20	0.0343
369-51-2 RL	STATION EQUIPMENT -**original cost only fully amortized**			-20	0.0063
369-52-2 ASL	SUPERVISORY EQUIPMENT	22	L1.5	-25	0.0000
369-52-2 RL	SUPERVISORY EQUIPMENT- **original cost only fully amortized**			-25	0.0000

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462
Depreciation Factors and Rates

Effective as of 7/1/24

COMMON

Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate
390-00-4	General Structures & Improvements	60	R1	-50	0.0250
390-05-4	STRUCTURES & IMPROV - MINOR EQUIP.	40	R2	-50	0.0375
390-07-4	STRUCTURES & IMPROV - MAJOR EQUIP.	40	R1.5	-50	0.0375
390-15-4	STRUCTURES & IMPROV - LANDSCAPING	40	R0.5	-50	0.0375
392-10-4	Transportation Equip- Electric	12	L2.5	+10	0.0750
392-20-4	Transportation Equip- Gas	12	L2.5	+10	0.0750
392-40-4	Transportation Equip- Common	12	L2.5	+10	0.0750
396-10-4	Power Operated Equip- Electric	13	L2.5	+10	0.0692
396-20-4	Power Operated Equip- Gas	13	L2.5	+15	0.0692
396-40-4	Power Operated Equip- Common	13	L2.5	+15	0.0692

COMMON VINTAGE

Account	Account Description	ASL	Type	%	Rate
391-11-4	EDP Equip- System and Main Frame	8	SQ	+0	0.1250
391-12-4	EDP- Systems Operations - SCADA	10	SQ	+0	0.0989
391-21-4	Data Handling Equipment	10	SQ	+0	0.1000
391-22-4	Office Furniture	15	SQ	+0	0.0667
393-00-4	Stores Equipment	25	SQ	+0	0.4000
393-20-4	Stores Equipment- Forklifts	25	SQ	+0	0.4000
394-10-4	Garage & Repair Equipment	25	SQ	+0	0.0355
394-20-4	Shop Equipment	25	SQ	+0	0.0180
394-30-4	Tools & Work Equipment	25	SQ	+0	0.0392
395-10-4	Laboratory Equipment	25	SQ	+0	0.4000
395-20-4	Laboratory Equipment- R&D	0	SQ	+0	0.0000
397-10-4	Communication Equipment - Radio	10	SQ	+0	0.1000
397-20-4	Communication Equipment - Telephone	10	SQ	+0	0.1000
398-00-4	Miscellaneous General Equipment	20	SQ	+0	0.0500

Appendix L, Schedule 1

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Capital Structure and Allowed Rate of Return
($000)

Rate Year 1:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$1,496,941	51.8%	4.65%	2.41%	2.41%
Customer Deposits	6,686	0.2%	3.00%	0.01%	0.01%
Common Equity	1,385,284	48.0%	9.50%	4.56%	6.17%
	$2,888,911	100.0%		6.97%	8.59%

Rate Year 2:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$1,619,651	51.8%	4.87%	2.52%	2.52%
Customer Deposits	6,686	0.2%	3.00%	0.01%	0.01%
Common Equity	1,501,580	48.0%	9.50%	4.56%	6.17%
	$3,127,917	100.0%		7.09%	8.70%

Rate Year 3:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$1,705,664	51.8%	5.01%	2.60%	2.60%
Customer Deposits	6,686	0.2%	3.00%	0.01%	0.01%
Common Equity	1,582,392	48.0%	9.50%	4.56%	6.17%
	$3,294,742	100.0%		7.16%	8.77%

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462

LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST FOR THE TWELVE MONTHS ENDING JUNE 30, 2026

	Maturity Date	Interest Rate %	Principal Amount Outstanding 6/30/2024	Charges During Rate Year	Months Outstanding	Average Amount Outstanding During Rate Year	Interest Expense During Rate Year
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Long Term Debt							
Outstanding Issues							
2005 Series E @ 5.84%	December 5, 2035	5.84	24,000	-	12	24,000	1,402
2006 Series E @ 5.76%	November 17, 2031	5.76	27,000	-	12	27,000	1,555
2007 Series F @ 5.80%	March 23, 2037	5.80	33,000	-	12	33,000	1,915
2009 Series F @ 5.80%	November 1, 2039	5.80	24,000	-	12	24,000	1,392
2010 Series G @ 5.716%	April 1, 2041	5.72	30,000	-	12	30,000	1,715
2011 Series G @ 4.707%	April 1, 2042	4.71	10,000	-	12	10,000	471
2012 Series G @ 4.776%	April 1, 2042	4.78	48,000	-	12	48,000	2,292
2012 Series G @ 4.065%	October 1, 2042	4.07	24,000	-	12	24,000	976
2010 Series B @ 5.64%	September 21, 2040	5.64	24,000	-	12	24,000	1,354
2013 Series D @ 4.09%	December 2, 2028	4.09	16,700	-	12	16,700	683
2016 Series H @ 2.56%	October 28, 2026	2.56	10,000	-	12	10,000	256
2016 Series I @ 3.63%	October 28, 2046	3.63	20,000	-	12	20,000	726
2017 Series J @4.05%	August 31, 2047	4.05	30,000	-	12	30,000	1,215
2017 Series K @4.2%	August 31, 2057	4.20	30,000	-	12	30,000	1,260
2018 Series L @ 4.27%	June 15, 2048	4.27	25,000	-	12	25,000	1,068
2018 Series M @ 3.99%	October 28, 2026	3.99	40,000	-	12	40,000	1,596
2018 Series N @ 4.20%	October 28, 2033	4.20	40,000	-	12	40,000	1,680
2019 Series O @ 3.89%	October 28, 2049	3.89	50,000	-	12	50,000	1,945
2019 Series P @ 3.99%	October 28, 2059	3.99	50,000	-	12	50,000	1,995
2020 Series Q @3.42%	May 14, 2050	3.42	30,000	-	12	30,000	1,026
2020 Series R @ 3.62%	July 14, 2060	3.62	30,000	-	12	30,000	1,086
2020 Series S @ 2.03%	September 28, 2030	2.03	40,000	-	12	40,000	812
2020 Series T @ 2.03%	November 17, 2030	2.03	30,000	-	12	30,000	609
2021 Series U @ 3.29%	March 16, 2051	3.29	75,000	-	12	75,000	2,468
2021 Series V @ 3.22%	October 29, 2051	3.22	55,000	-	12	55,000	1,771
2022 Series W @ 2.37%	January 27, 2027	2.37	50,000	-	12	50,000	1,185
2022 Series X @ 2.59%	January 27, 2029	2.59	60,000	-	12	60,000	1,554
2022 Series Y @ 5.07%	September 28, 2032	5.07	100,000	-	12	100,000	5,070
2022 Series Z @ 5.42%	September 28, 2052	5.42	10,000	-	12	10,000	542
2023 Series AA @ 5.68%	March 28, 2033	5.68	40,000		12	40,000	2,272
2023 Series BB @ 5.78%	March 28, 2035	5.78	15,000	-	12	15,000	867
2023 Series CC @ 5.88%	March 28, 2038	5.88	35,000	-	12	35,000	2,058
2023 Series DD @ 6.17%	November 7, 2028	6.17	60,000	-	12	60,000	3,702
2024 Series EE @ 5.59%	April 9, 2031	5.59	25,000	-	12	25,000	1,398
2024 Series FF @ 5.69%	April 9, 2034	5.69	35,000	-	12	35,000	1,992
2024 Series EE @ 4.88%	October 16, 2029	4.88	25,000	-	12	25,000	1,220
2024 Series GG @ 5.3%	October 16, 2034	5.30	44,000	-	12	44,000	2,332
2024 Series II @ 5.4%	October 16, 2036	5.40	35,000	-	12	35,000	1,890
2025 New Issuance	February 1, 2045	6.15	80,000	-	12	80,000	4,920
2025 New Issuance	August 1, 2045	6.15	-	60,000	11	55,000	3,383
2026 New Issuance	February 1, 2046	6.10	-	45,000	5	18,750	1,144
Average Unamortized Debt Issuance Cost						(6,509)	
Average Long Term Debt Outstanding			1,429,700	105,000		$ 1,496,941	
Interest Charges for the Rate Year							$ 68,794
Plus: Amortization of Debt Discount and Expense							952
Less: Amortization of Premium on Debt							-
Total Cost of Debt							
Amount							$ 69,746
% of Average Long Term Debt Outstanding							4.66%
Settlement Adjustment							-0.01%
% of Average Long Term Debt Outstanding - SETTLEMENT							**4.65%**

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462

LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST FOR THE TWELVE MONTHS ENDING JUNE 30, 2027
($000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2024 (3)	Charges During Rate Year (4)	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt							
Outstanding Issues							
2005 Series E @ 5.84%	December 5, 2035	5.84	24,000	-	12	24,000	1,402
2006 Series E @ 5.76%	November 17, 2031	5.76	27,000	-	12	27,000	1,555
2007 Series F @ 5.80%	March 23, 2037	5.80	33,000	-	12	33,000	1,915
2009 Series F @ 5.80%	November 1, 2039	5.80	24,000	-	12	24,000	1,392
2010 Series G @ 5.716%	April 1, 2041	5.72	30,000	-	12	30,000	1,715
2011 Series G @ 4.707%	April 1, 2042	4.71	10,000	-	12	10,000	471
2012 Series G @ 4.776%	April 1, 2042	4.78	48,000	-	12	48,000	2,292
2012 Series G @ 4.065%	October 1, 2042	4.07	24,000	-	12	24,000	976
2010 Series B @ 5.64%	September 21, 2040	5.64	24,000	-	12	24,000	1,354
2013 Series D @ 4.09%	December 2, 2028	4.09	16,700	-	12	16,700	683
2016 Series H @ 2.56%	October 28, 2026	2.56	10,000	(10,000)	4	3,333	85
2016 Series I @ 3.63%	October 28, 2046	3.63	20,000	-	12	20,000	726
2017 Series J @4.05%	August 31, 2047	4.05	30,000	-	12	30,000	1,215
2017 Series K @4.2%	August 31, 2057	4.20	30,000	-	12	30,000	1,260
2018 Series L @ 4.27%	June 15, 2048	4.27	25,000	-	12	25,000	1,068
2018 Series M @ 3.99%	October 28, 2026	3.99	40,000	(40,000)	4	13,333	532
2018 Series N @ 4.20%	October 28, 2033	4.20	40,000	-	12	40,000	1,680
2019 Series O @ 3.89%	October 28, 2049	3.89	50,000	-	12	50,000	1,945
2019 Series P @ 3.99%	October 28, 2059	3.99	50,000	-	12	50,000	1,995
2020 Series Q @3.42%	May 14, 2050	3.42	30,000	-	12	30,000	1,026
2020 Series R @ 3.62%	July 14, 2060	3.62	30,000	-	12	30,000	1,086
2020 Series S @ 2.03%	September 28, 2030	2.03	40,000	-	12	40,000	812
2020 Series T @ 2.03%	November 17, 2030	2.03	30,000	-	12	30,000	609
2021 Series U @ 3.29%	March 16, 2051	3.29	75,000	-	12	75,000	2,468
2021 Series V @ 3.22%	October 29, 2051	3.22	55,000	-	12	55,000	1,771
2022 Series W @ 2.37%	January 27, 2027	2.37	50,000	(50,000)	7	29,167	691
2022 Series X @ 2.59%	January 27, 2029	2.59	60,000	-	12	60,000	1,554
2022 Series Y @ 5.07%	September 28, 2032	5.07	100,000	-	12	100,000	5,070
2022 Series Z @ 5.42%	September 28, 2052	5.42	10,000	-	12	10,000	542
2023 Series AA @ 5.68%	March 28, 2033	5.68	40,000		12	40,000	2,272
2023 Series BB @ 5.78%	March 28, 2035	5.78	15,000	-	12	15,000	867
2023 Series CC @ 5.88%	March 28, 2038	5.88	35,000	-	12	35,000	2,058
2023 Series DD @ 6.17%	November 7, 2028	6.17	60,000	-	12	60,000	3,702
2024 Series EE @ 5.59%	April 9, 2031	5.59	25,000	-	12	25,000	1,398
2024 Series FF @ 5.69%	April 9, 2034	5.69	35,000	-	12	35,000	1,992
2024 Series GG @ 4.88%	October 16, 2029	4.88	25,000	-	12	25,000	1,220
2024 Series HH @ 5.3%	October 16, 2034	5.30	44,000	-	12	44,000	2,332
2024 Series II @ 5.4%	October 16, 2036	5.40	35,000	-	12	35,000	1,890
2025 New Issuance	February 1, 2045	6.15	80,000	-	12	80,000	4,920
2025 New Issuance	August 1, 2045	6.15	60,000	-	12	60,000	3,690
2026 New Issuance	February 1, 2046	6.10	45,000	-	12	45,000	2,745
2026 New Issuance	September 1, 2046	6.10	-	135,000	10	112,500	6,863
2027 New Issuance	February 1, 2047	6.10	-	80,000	5	33,333	2,033
Average Unamortized Debt Issuance Cost						(6,716)	
Average Long Term Debt Outstanding			1,534,700	115,000		$1,619,651	
Interest Charges for the Rate Year							$ 77,870
Plus: Amortization of Debt Discount and Expense							929
Less: Amortization of Premium on Debt							-
Total Cost of Debt							
Amount							$ 78,799
% of Average Long Term Debt Outstanding							4.87%

Appendix L, Schedule 2
Sheet 3 of 3
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462

LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST FOR THE TWELVE MONTHS ENDING JUNE 30, 2028
($000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2024 (3)	Charges During Rate Year (4)	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt							
Outstanding Issues							
2005 Series E @ 5.84%	December 5, 2035	5.84	24,000	-	12	24,000	1,402
2006 Series E @ 5.76%	November 17, 2031	5.76	27,000	-	12	27,000	1,555
2007 Series F @ 5.80%	March 23, 2037	5.80	33,000	-	12	33,000	1,915
2009 Series F @ 5.80%	November 1, 2039	5.80	24,000	-	12	24,000	1,392
2010 Series G @ 5.716%	April 1, 2041	5.72	30,000	-	12	30,000	1,715
2011 Series G @ 4.707%	April 1, 2042	4.71	10,000	-	12	10,000	471
2012 Series G @ 4.776%	April 1, 2042	4.78	48,000	-	12	48,000	2,292
2012 Series G @ 4.065%	October 1, 2042	4.07	24,000	-	12	24,000	976
2010 Series B @ 5.64%	September 21, 2040	5.64	24,000	-	12	24,000	1,354
2013 Series D @ 4.09%	December 2, 2028	4.09	16,700	-	12	16,700	683
2016 Series I @ 3.63%	October 28, 2046	3.63	20,000	-	12	20,000	726
2017 Series J @4.05%	August 31, 2047	4.05	30,000	-	12	30,000	1,215
2017 Series K @4.2%	August 31, 2057	4.20	30,000	-	12	30,000	1,260
2018 Series L @ 4.27%	June 15, 2048	4.27	25,000	-	12	25,000	1,068
2018 Series N @ 4.20%	October 28, 2033	4.20	40,000	-	12	40,000	1,680
2019 Series O @ 3.89%	October 28, 2049	3.89	50,000	-	12	50,000	1,945
2019 Series P @ 3.99%	October 28, 2059	3.99	50,000	-	12	50,000	1,995
2020 Series Q @3.42%	May 14, 2050	3.42	30,000	-	12	30,000	1,026
2020 Series R @ 3.62%	July 14, 2060	3.62	30,000	-	12	30,000	1,086
2020 Series S @ 2.03%	September 28, 2030	2.03	40,000	-	12	40,000	812
2020 Series T @ 2.03%	November 17, 2030	2.03	30,000	-	12	30,000	609
2021 Series U @ 3.29%	March 16, 2051	3.29	75,000	-	12	75,000	2,468
2021 Series V @ 3.22%	October 29, 2051	3.22	55,000	-	12	55,000	1,771
2022 Series X @ 2.59%	January 27, 2029	2.59	60,000	-	12	60,000	1,554
2022 Series Y @ 5.07%	September 28, 2032	5.07	100,000	-	12	100,000	5,070
2022 Series Z @ 5.42%	September 28, 2052	5.42	10,000	-	12	10,000	542
2023 Series AA @ 5.68%	March 28, 2033	5.68	40,000		12	40,000	2,272
2023 Series BB @ 5.78%	March 28, 2035	5.78	15,000	-	12	15,000	867
2023 Series CC @ 5.88%	March 28, 2038	5.88	35,000	-	12	35,000	2,058
2023 Series DD @ 6.17%	November 7, 2028	6.17	60,000	-	12	60,000	3,702
2024 Series EE @ 5.59%	April 9, 2031	5.59	25,000	-	12	25,000	1,398
2024 Series GG @ 4.88%	April 9, 2034	5.69	35,000	-	12	35,000	1,992
2024 Series HH @ 5.3%	October 16, 2029	4.88	25,000	-	12	25,000	1,220
2024 Series II @ 5.4%	October 16, 2034	5.30	44,000	-	12	44,000	2,332
2024 Series II @ 5.4%	October 16, 2036	5.40	35,000	-	12	35,000	1,890
2025 New Issuance	February 1, 2045	6.15	80,000	-	12	80,000	4,920
2025 New Issuance	August 1, 2045	6.15	60,000	-	12	60,000	3,690
2026 New Issuance	February 1, 2046	6.10	45,000	-	12	45,000	2,745
2026 New Issuance	September 1, 2046	6.10	135,000	-	12	135,000	8,235
2027 New Issuance	February 1, 2047	6.10	80,000	-	12	80,000	4,880
2027 New Issuance	July 1, 2047	6.10	-	60,000	12	60,000	3,660
2028 New Issuance	June 1, 2048	6.10	-	30,000	1	2,500	153
Average Unamortized Debt Issuance Cost						(6,536)	
Average Long Term Debt Outstanding			1,649,700	90,000		$1,705,664	
Interest Charges for the Rate Year							$ 84,593
Plus: Amortization of Debt Discount and Expense							904
Less: Amortization of Premium on Debt							-
Total Cost of Debt							
Amount							$ 85,496
% of Average Long Term Debt Outstanding							5.01%

Appendix L, Schedule 3

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric and Gas Basis Point Values

Basis Point Values:	Electric		
	RY1	**RY2**	**RY3**
Rate Base ($000)	$2,010,683	$2,148,066	$2,242,919
x Equity Ratio	48%	48%	48%
Equity component of Rate Base ($000)	$965,128	$1,031,072	$1,076,601
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$96,500	$103,100	$107,700
Pre-tax value of 1 BP - whole dollars	$130,600	$139,600	$145,800

Basis Point Values:	Gas		
	RY1	**RY2**	**RY3**
Rate Base ($000)	$801,154	$859,581	$908,861
x Equity Ratio	48%	48%	48%
Equity component of Rate Base ($000)	$384,554	$412,599	$436,253
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$38,500	$41,300	$43,600
Pre-tax value of 1 BP - whole dollars	$52,100	$55,900	$59,000

Appendix L, Schedule 4

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric and Gas Basis Point Values on Calendar Year Basis

Electric Pre-Tax Basis Point Values		2025 [1]	2026 [2]	2027 [3]	2028 [4]
Cases 23-E-0418 et al., Appendix 2	RY3	116,189	n/a	n/a	n/a
Cases 24-E-0461 et al., Appendix L Schedule 3	RY1	130,600	130,600	n/a	n/a
Cases 24-E-0461 et al., Appendix L Schedule 3	RY2	n/a	139,600	139,600	n/a
Cases 24-E-0461 et al., Appendix L Schedule 3	RY3	n/a	n/a	145,800	145,800
Pre-tax value of 1 BP - whole dollars		123,395	135,100	142,700	145,800

Gas Pre-Tax Basis Point Values					
Cases 23-G-0419 et al., Appendix 2	RY3	46,620	n/a	n/a	n/a
Cases 24-G-0462 et al., Appendix L Schedule 3	RY1	52,100	52,100	n/a	n/a
Cases 24-G-0462 et al., Appendix L Schedule 3	RY2	n/a	55,900	55,900	n/a
Cases 24-G-0462 et al., Appendix L Schedule 3	RY3	n/a	n/a	59,000	59,000
Pre-tax value of 1 BP - whole dollars		49,360	54,000	57,450	59,000

Notes:

[1] Average of Cases 23-E-0418 et al. RY3 and Cases 24-E-0461 et al. RY1

[2] Average of RY1 and RY2.

[3] Average of RY2 and RY3.

[4] Based on RY3 and will remain in effect for all Calendar Years forward until modified by a Commission Order.

Appendix L, Schedule 5

Central Hudson Gas & Electric Corporation
Case 24-E-0461 & Case 24-G-0462
Illustrative Example of Earnings Sharing Partial Year
Stub Period Starting July 1, 2028
($000)

Assumption: CHGE Delays Filing for 6 Months & Files for New Electric Rates Effective January 1, 2029

Month / Year	Electric Regulatory Operating Income	
July-28	$ 15,000	
August-28	15,000	
September-28	15,000	
October-28	15,500	
November-28	14,500	
December-28	14,500	
Total for Stub Period		$ 89,500

	Electric Rate Base	
Actual Average Rate Base @ December 31, 2028	$ 2,300,000	
x Ratio of book operating income for July 2027 - December 2027 to book operating income for the 12 months ended June 2028	52.0%	
Rate Base Subject to Earnings Test		$ 1,196,000

				Earnings Sharing Calculation
Regulatory Rate of Return	$ 89,500	/	$ 1,196,000	7.48%
Regulatory Return on Equity (Below)				10.15%
Earnings Sharing Threshold				10.00%
Earnings Above / (Under) Threshold				0.15%
Basis Point ("BP") Equivalent				15
Pre-Tax Value of BP for TME June 30, 2028 (Appendix L, Schedule 3)				$ 145.8
Pre-Tax Earnings Subject to Sharing				$ 2,187
Sharing @ 50/50 - Amount Deferred for Customer Benefit				$ 1,094

RATEMAKING CAPITALIZATION FOR ESM

	Capital Structure %	Cost Rate	Weighted Average Cost of Capital
Long Term Debt	51.80%	5.01%	2.60%
Customer Deposits	0.20%	3.00%	0.01%
Common Equity [1]	48.00%	10.15%	4.87%
Total	100.00%		7.48%

Note: the approach illustrated above would also apply to a delay in filing a gas case.

[1] - Reflects the lesser of an equity ratio equal to 50% or Central Hudson's actual average common equity ratio.

Appendix M

Central Hudson Gas and Electric Corporation
Cases 24-E-0461 and 24-G-0462
New, Modified and Continuing* Reporting Requirements

Topic	JP Section	Type	Frequency/Due Date
Capital Expenditures	V.A.5	Variance reporting	Quarterly - Due within 45 days of the end of each quarter. In lieu of a report for the fourth quarter, the Company will submit an annual report by March 1st of the next calendar year.
		Prior Calendar Year	Annually due March 1
		Five Year Capital Investment Plan	Annually due July 1
Minor Storm Reporting (Non-Major Storms)	VIII.A, Appendix G	Reporting on Non-Major Storm Restoration events and expenses incurred during the preceding quarter with details as described in the JP.	Quarterly - Due within 45 days of the end of each quarter.
Vegetation Management Reporting	VIII.B	Reporting on the Distribution Vegetation Management program expenses by activity and on the Hazard Tree Removal Program.	Quarterly - Due within 45 days of the end of each quarter.
Physical and Cyber Security Projects and Programs	V.A.5	Status report on project spending and schedules for each security project and program filed with the Commission secretary, highlighting and explaining significant changes to the projects/programs.	Twice yearly
		Report made to Staff regarding physical or cybersecurity projects that (1) reach significant milestones, merge with other projects, or are discontinued and (2) when significant changes are made to cybersecurity related FTEs.	Quarterly
Energy Affordability Program (EAP)	XI.D.	Monthly EAP self-enrollments will be recorded and reported within existing reporting in Case 14-M-0565.	Monthly
Cloud-based or SaaS IT solutions	V.B.1.i, Appendix F	Notice of deferral	As needed
Sales Tax Refunds and Assessments	V.B.1.vvv, Appendix F	Continue to file notice or include refunds in its PSC reports as required under PSL Section 89.3	As needed
Property Tax Refunds and Assessments	V.B.1.jjj, Appendix F	Continue to file notice or include refunds in its PSC reports as required under PSL Section 89.3	As needed
Fortis Overhead Allocation Methodology	V.H.	Notice of change in methodology	As needed - Due within 60 days after effective date of revised cost allocation
Reporting and Calculation of Actual Regulatory Earnings	VII.B.	Computation of actual regulatory earnings for the preceding Rate Year and schedule of regulatory deferral balances recorded during the year.	Annually - Within 90 days following the end of each Rate Year
Retail Access Program Collaborative Process	XXIV.B.	Report summarizing the conclusions of the collaborative (to be initiated prior to end of Rate Year 1), including any resulting changes to the Company's Gas Transportation Operating Procedures Manual ("GTOP"), by the end of Rate Year 2.	As needed (at conclusion of collaborative by the end of Rate Year 2)
Economic Development	XIII.B.	Details economic activity for the prior calendar year	Annually due April 1
		Separate chapter for the Workforce Clean Energy Program reporting, including education/training programs funded, determination methodology for grant award amounts, intended results of awarded grants, number of participants in awarded programs, methodology for tracking participant outcomes, additional assistance applied for and received by applicants, and participant feedback.	
Rate Adjustment Mechanism	XV., Appendix H	Compliance filing	Annually due March 31
Electric Reliability Performance Mechanisms	XVI., Appendix S	Annual Reporting	Annually due March 31
Gas Safety Metric - Record Violations Over Annual Cap	XVII.D., Appendix U	Remediation Plan	As needed - Due within 90 days of Pipeline Safety Staff's audit letter
Gas Community Emergency Response Drills	XVII.G.1	Invitee and attendance reporting, schedule of activities, detailed event summary, cost of event	As needed - invitees and schedule provided prior to the event, summary, attendance, and costs provided within 30 days after the event
Gas Weather Normalization Adjustment	VIII.C.2	Annual statement and associated WNA workpapers when WNA factors are reset.	Annual (monthly requirements removed)
Differentiated Gas Purchases	XXIII.B	Details of purchases of differentiated gas, including the name of the certifier, the volume of differentiated gas purchased, and the methane intensity of differentiated gas and the cost per unit, along with the steps the Company undertakes when purchasing differentiated gas.	Monthly
Call Center Legislation Reporting	XVIII.B.	The Company will file quarterly reports, with a monthly breakdown, that details the following: (1) Call Center customer service representative ("CSR") staffing levels; (2) Status of hiring; (3) CSR training activity; (4) Overall spending broken out by category identified above (labor, training, equipment, office space); and (5) Additional expenses outside of the categories identified in item (4) will be accompanied by an explanation and justification of each.	Quarterly, with monthly breakdown
Credit/Debit Card Payment and Walk-in Payment Fees	2018 Joint Proposal - XVIII.B.1.	Reporting will include administrative processing fees; per transaction rates; and actual and expected levels of customer participation.	Annual with monthly breakdown
Customer Service Performance Indicators	XVIII.A.	Customer Performance Indicators as per Case 15-M-0566, including the following enhanced reporting: a. the number of calls answered by a representative within 30 seconds; b. the number of calls answered by a representative in more than 30 and at most 60 seconds; c. the number of calls answered by a representative in over one minute and at most five minutes; d. the number of calls answered by a representative in over five minutes and at most 60 minutes; and e. the number of calls answered by a representative in more than one hour. In addition, the Company will file an annual CSPI report detailing its CSPI performance for the previous calendar year, any NRAs incurred for missed metric targets, an explanation of any issues that affected performance, what was done well, and what improvements the Company will focus on the following year.	Monthly; Annual
Language Access	XVIII.C.	Following the implementation of the plan to code previously uncoded residential customer accounts as LEP when a customer self-identifies during the collections process, and provide a 15-day extension during which the Company will not pursue service termination at the end of Rate Year 2, the Company will track and report on this program on an annual basis and file such reports with the Secretary to the Commission in these rate proceedings.	Annual
Outreach and Education	XIX.	Annual Outreach and Education Reports	Annually due April 1
Earnings Adjustment Mechanisms	XXI.A.	Annual Reporting	Annually due June 1
Major Storm Reserve	Appendix G	Reporting of Eligible Costs, Mutual Aid Retainer Payments, and Pre-Staging Events	As Needed - Due Within 120 days of the date on which the Company is able to serve all customers

* For the purposes of this Appendix, continuing is defined as reporting requirements that continue from the 2020 Joint Proposal.

Appendix M, Schedule A

Central Hudson Gas and Electric Corp.
Case 24-E-0461 Joint Proposal
Minor Storm Expense Report
Rate Year Ending 06/30/20YY
Update for MM/DD/YYYY through MM/DD/YYYY

			July - September 20YY Total	October - December 20YY Total	January 20YY - March 20YY Total	April 20YY - June 20YY Total	Rate Year Ending June 30, 20YY Total	Total Rate Year 2 (July 20YY - June 20YY)	Total Rate Year 1 (July 20YY - June 20YY)	Total To-Date 3-Year Rate Plan Ending June 20YY
		Class 1 or Greater Storm Events								
Proactive	**Internal**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Base Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Overtime	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Employee Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Materials	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transportation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	External		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Accounts Payable - Contract Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reactive	**Internal**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Base Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Overtime	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Employee Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Materials	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transportation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	External		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Accounts Payable - Contract Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Less Severe Than Class 1 Events (A)								
	Internal		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Base Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Overtime	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Employee Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Materials	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transportation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	External		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Accounts Payable - Contract Labor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Pre-Staging & Mobilization Costs Outside of the Major Storm Reserve (B)									
		MM DD, YYYY Pre-Staging Event	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		MM DD, YYYY Pre-Staging Event	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		MM DD, YYYY Pre-Staging Event	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Sub-total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Grand Total		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

(A) Entries for Less Severe than Class 1 Storms are not tracked to reflect proactive/reactive costs. However, most costs here can be assumed to be reactive.
(B) Represents the portion of pre-staging costs charged to non-major storm expense per the Pre-Staging and Mobilization provisions of the Major Storm Reserve, which is recorded as a single Journal Voucher on the Company's records.

Appendix M, Schedule A

Central Hudson Gas and Electric Corporation
Case 24-E-0461 Joint Proposal
Incremental Minor Storm Expense Report
4th Quarter of Rate Year Ending 2024
(Jul 1, 2023 through June 30, 2024)

				Storm Date and Event Type						Customer Outages								Cases of Trouble						# FTE Assisting w/Restoration					
Event Description:	Minor Storm Event No.	PRE-STAGING (Y/N)	Total Costs	Date	Weekday M-TH	Weekend Fri / Sat / Sun	Event Type Primary Condition	Event Type Secondary Condition	DTN EEI-Index	Total Cust. Affected	95% Restored from Peak in "X" hrs.	Peak Cust. Out	Catskill	Fishkill	Kingston	Newburgh	Poughkeepsie	Total	Catskill	Fishkill	Kingston	Newburgh	Poughkeepsie	Total FTE	Line FTE	Vegetation Mgmt FTE	Other Support Personnel FTE	# of Broken Poles	Notes - Description of the event to help with any clarifications
July 20YY Wind & Rain Storm	1		$65,125	**7/1/20YY**		x	Wind	Rain	3	28,635		17,199	2,561	0	12,571	13,503	0	358	26	0	126	135	0	53	35	8	10	25	
July 20YY Thunderstorm	2		$20,150	**7/5/20YY**	x		Thunderstorm	Wind	2	6,592		3,531	1,127	15	4,400	50	1,000	102	11	0	44	1	10	24	15	4	5	15	
	3																												
	4																												
	5																												
	6																												
	7																												
	8																												
	9																												
	10																												
	11																												
	12																												
	13																												
	14																												
	15																												

Appendix M, Schedule B

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462

	January	February	March	April	May	June	July	August	September	October	November	December	Total	Notes
Trouble Orders														
Planned - Expenditures													-	
Actual- Expenditures													-	
On Road														
Planned Expenditures													-	
Actual Expenditures													-	
Planned Miles													-	
Actual Miles													-	
Contractor Name														
Off Road														
Planned Expenditures													-	
Actual Expenditures													-	
Planned Miles													-	
Actual Miles													-	
Contractor Name														
Danger Trees*														
Planned Expenditures													-	
Actual Expenditures													-	
Actual Trees Removed													-	
Hazard Trees**														
Planned Expenditures													-	
Actual Expenditures													-	
Planned Crewing (No.)													-	
Actual Crewing (No.)													-	
Actual Trees Removed													-	
Cost per tree														
Total Hazard Tree Inventory (includes backlog)														
Total Trees that can't be removed safely with 100' Bucket														
Total Trees Remaining in Backlog														
Total Trees in Inventory to be Made Safe/Removed														
Contractor Name														
Flagging														
Planned Expenditures													-	
Actual Expenditures													-	
Total - Distribution Line Clearance Program														
Planned Expenditures													-	
Actual Expenditures													-	
Planned Miles													-	
Actual Miles													-	
Actual Tree Removals													-	

*Danger Tree planned expenditures are based on historical averages and fluctuate monthly and yearly.
**Central Hudson Gas & Electric does not plan the number of Hazard Trees to be removed in a given month/year, it is based on funding to operate approved crewing on an annual basis.

Appendix M, Schedule B

Sample Template for Reports Regarding Calendar Year 2025
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462

On-Road Modified Enhanced Line Clearance

	2020		2021		2022		2023		2024		2025	
	Miles	Expenditures	Miles	Expenditures	Miles	Expenditures	Miles	Expenditures	Miles	Expenditures	Miles	Expenditures
January												
February												
March												
April												
May												
June												
July												
August												
September												
October												
November												
December												
Total												

Flagging Costs Modified Enhanced Line Clearance

	2020 Expenditures	2021 Expenditures	2022 Expenditures	2023 Expenditures	2024 Expenditures	2025 Expenditures
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						
Total						

Off-Road Modified Enhanced Line Clearance

	2020		2021		2022		2023		2024		2025	
	Miles	Expenditures	Miles	Expenditures	Miles	Expenditures	Miles	Expenditures	Miles	Expenditures	Miles	Expenditures
January												
February												
March												
April												
May												
June												
July												
August												
September												
October												
November												
December												
Total												

		On- Road			Off-Road	
			Cost			
Time Period	Months	Miles	w/o Flagging	w/Flagging	Miles	Cost
1/1/2020 - 12/31/2020	12					
1/1/2021 - 12/31/2021	12					
1/1/2022 - 12/31/2022	12					
1/1/2023 - 12/31/2023	12					
1/1/2024 - 12/31/2024	12					
Total:						

Appendix N Sheet 1 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Sales (MWh) by Service Classification

		Twelve Months Ended June 30, 2026	Twelve Months Ended June 30, 2027	Twelve Months Ended June 30, 2028
Service Classification No. 1				
	Heating	471,125	541,874	626,215
	Nonheating	1,856,371	1,855,555	1,870,142
		2,327,496	2,397,429	2,496,357
Service Classification No. 2				
	Nondemand	211,668	218,579	226,930
	Primary	222,628	223,473	224,013
	Secondary	1,332,903	1,342,660	1,351,771
		1,767,199	1,784,711	1,802,714
Service Classification No. 3		321,512	322,559	323,176
Service Classification No. 5		11,540	11,400	11,280
Service Classification No. 6		19,830	19,830	19,830
Service Classification No. 8		10,910	10,900	10,900
Service Classification No. 9		720	720	720
Service Classification No. 13				
	Transmission	620,960	620,960	620,960
	Substation	105,250	104,790	104,790
		726,210	725,750	725,750
Interdepartmental		915	915	915
Total Own Territory		5,186,332	5,274,214	5,391,642

Appendix N Sheet 2 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Base Delivery Revenues by Service Classification

		Twelve Months Ended June 30, 2026	Twelve Months Ended June 30, 2027	Twelve Months Ended June 30, 2028
Service Classification No. 1				
	Heating	$ 77,471,580	$ 93,841,180	$ 112,119,070
	Nonheating	$ 328,251,390	$ 343,117,310	$ 354,913,030
		$ 405,722,970	$ 436,958,490	$ 467,032,100
Service Classification No. 2				
	Nondemand	$ 38,995,450	$ 41,857,580	$ 44,367,600
	Primary	$ 7,856,152	$ 8,319,826	$ 8,602,088
	Secondary	$ 97,280,222	$ 103,041,618	$ 107,129,952
		$ 144,131,824	$ 153,219,024	$ 160,099,640
Service Classification No. 3		$ 12,078,576	$ 12,773,356	$ 13,232,728
Service Classification No. 5		$ 3,101,540	$ 3,276,400	$ 3,386,020
Service Classification No. 6		$ 2,711,670	$ 2,853,090	$ 2,949,210
Service Classification No. 8		$ 6,221,546	$ 6,506,970	$ 6,707,670
Service Classification No. 9		$ 224,920	$ 236,400	$ 243,380
Service Classification No. 13				
	Transmission	$ 8,792,530	$ 9,403,270	$ 9,831,030
	Substation	$ 2,736,066	$ 2,680,744	$ 2,772,158
		$ 11,528,596	$ 12,084,014	$ 12,603,188
Interdepartmental		$ 96,330	$ 96,330	$ 96,330
Total Own Territory		$ 585,817,972	$ 628,004,074	$ 666,350,266

Appendix N Sheet 3 of 20

Central Hudson Gas & Electric Corporation

Cases 24-E-0461 & 24-G-0462

Summary of Electric Customers by Service Classification

	Twelve Months Ended June 30, 2026	Twelve Months Ended June 30, 2027	Twelve Months Ended June 30, 2028
Service Classification No. 1			
Heating	37,689	44,251	51,949
Nonheating	233,656	227,134	219,494
	271,345	271,384	271,443
Service Classification No. 2			
Nondemand	34,988	35,055	35,135
Primary	152	153	150
Secondary	11,457	11,500	11,528
	46,597	46,708	46,813
Service Classification No. 3	37	37	37
Service Classification No. 5	3,813	3,760	3,707
Service Classification No. 6	1,400	1,400	1,400
Service Classification No. 8	212	212	212
Service Classification No. 9	59	58	57
Service Classification No. 13			
Transmission	6	6	6
Substation	5	4	4
	11	10	10
Interdepartmental	1	1	1
Total Own Territory	323,474	323,569	323,679

Appendix N Sheet 4 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Demand Determinants by Service Classification

	Twelve Months Ended June 30, 2026	Twelve Months Ended June 30, 2027	Twelve Months Ended June 30, 2028
Service Classification No. 2			
Primary kW	550,521	552,604	553,942
Secondary kW	4,284,328	4,315,346	4,344,418
	4,834,849	4,867,950	4,898,360
Service Classification No. 3 kW	724,280	726,674	728,089
Service Classification No. 13			
Transmission kW	1,030,597	1,042,597	1,054,597
Substation kW	180,602	174,602	174,602
	1,211,199	1,217,199	1,229,199
Total kW	6,770,328	6,811,823	6,855,648
Service Classification No. 2 RkVa			
Primary RkVa	68,605	68,845	68,999
Secondary RkVa	131,821	132,753	133,622
	200,426	201,598	202,621
Service Classification No. 3 RkVa	85,820	86,118	86,303
Service Classification No. 13 RkVa			
Transmission RkVa	53,030	53,030	53,030
Substation RkVa	26,140	25,710	25,710
	79,170	78,740	78,740
Total RkVa	365,416	366,456	367,664

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Sales (MWh) by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2026)

	July 2025	August 2025	September 2025	October 2025	November 2025	December 2025	January 2026	February 2026	March 2026	April 2026	May 2026	June 2026	Total
Service Classification No. 1													
Heating	17,681	17,828	15,697	19,064	34,380	48,409	74,625	76,997	66,446	51,168	30,255	18,574	471,125
Nonheating	194,705	192,790	171,821	140,047	135,034	143,277	171,704	162,012	145,175	131,514	129,080	139,210	1,856,371
	212,386	210,618	187,518	159,112	169,414	191,686	246,330	239,009	211,620	182,682	159,336	157,784	2,327,496
Service Classification No. 2													
Nondemand	15,828	16,763	14,940	15,357	17,117	19,024	22,170	21,212	20,699	17,907	15,872	14,779	211,668
Primary	20,085	19,341	19,491	21,825	17,891	17,240	19,363	18,026	18,273	15,508	17,753	17,832	222,628
Secondary	131,836	132,843	120,698	107,348	99,188	104,354	114,697	107,899	104,624	97,068	102,729	109,619	1,332,903
	167,750	168,947	155,129	144,530	134,196	140,617	156,230	147,138	143,596	130,482	136,355	142,230	1,767,199
Service Classification No. 3	31,211	30,108	22,133	32,199	26,643	23,119	26,252	25,326	23,345	27,206	26,499	27,471	321,512
Service Classification No. 5	760	840	930	1,080	1,160	1,280	1,200	1,000	970	860	770	690	11,540
Service Classification No. 6													
Heating	1,040	970	860	960	760	1,120	1,310	900	930	810	900	860	11,420
Nonheating	790	760	910	710	680	810	680	530	660	590	660	630	8,410
	1,830	1,730	1,770	1,670	1,440	1,930	1,990	1,430	1,590	1,400	1,560	1,490	19,830
Service Classification No. 8	710	790	870	1,010	1,090	1,200	1,150	950	930	820	740	650	10,910
Service Classification No. 9	60	60	60	60	60	60	60	60	60	60	60	60	720
Service Classification No. 13													
Transmission	58,910	57,260	53,180	52,080	49,700	48,810	48,880	45,340	50,040	50,580	52,460	53,720	620,960
Substation	9,530	9,570	8,800	8,860	8,480	8,260	9,120	7,630	8,840	8,530	8,720	8,910	105,250
	68,440	66,830	61,980	60,940	58,180	57,070	58,000	52,970	58,880	59,110	61,180	62,630	726,210
Interdepartmental	95	90	80	65	75	80	80	70	80	75	60	65	915
Total	483,242	480,013	430,470	400,666	392,259	417,042	491,291	467,953	441,071	402,695	386,560	393,070	5,186,332

Appendix N Sheet 6 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Base Delivery Revenues (Excluding Revenue Tax) by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2026)

	July 2025	August 2025	September 2025	October 2025	November 2025	December 2025	January 2026	February 2026	March 2026	April 2026	May 2026	June 2026	Total
Service Classification No. 1													
Heating	$ 3,388,390	$ 3,395,490	$ 3,050,150	$ 3,536,490	$ 5,717,510	$ 7,709,370	$ 11,510,770	$ 11,827,420	$ 10,346,120	$ 8,178,330	$ 5,209,710	$ 3,601,830	$ 77,471,580
Nonheating	$ 33,247,480	$ 32,733,090	$ 29,963,750	$ 25,422,670	$ 24,632,160	$ 25,556,060	$ 29,903,910	$ 28,282,400	$ 25,941,540	$ 23,963,080	$ 23,660,660	$ 24,944,590	$ 328,251,390
	$ 36,635,870	$ 36,128,580	$ 33,013,900	$ 28,959,160	$ 30,349,670	$ 33,265,430	$ 41,414,680	$ 40,109,820	$ 36,287,660	$ 32,141,410	$ 28,870,370	$ 28,546,420	$ 405,722,970
Service Classification No. 2													
Nondemand	$ 3,007,810	$ 3,146,020	$ 2,888,800	$ 3,037,300	$ 3,195,560	$ 3,384,320	$ 3,829,930	$ 3,640,340	$ 3,636,820	$ 3,263,380	$ 3,066,760	$ 2,898,410	$ 38,995,450
Primary	$ 739,121	$ 680,921	$ 665,071	$ 809,751	$ 632,241	$ 593,751	$ 632,441	$ 643,581	$ 605,091	$ 598,141	$ 665,861	$ 590,181	$ 7,856,152
Secondary	$ 8,972,771	$ 8,961,621	$ 8,423,201	$ 9,374,941	$ 7,574,811	$ 7,352,671	$ 8,186,871	$ 7,386,151	$ 7,312,291	$ 7,323,241	$ 8,028,761	$ 8,382,891	$ 97,280,222
	$ 12,719,702	$ 12,788,562	$ 11,977,072	$ 13,221,992	$ 11,402,612	$ 11,330,742	$ 12,649,242	$ 11,670,072	$ 11,554,202	$ 11,184,762	$ 11,761,382	$ 11,871,482	$ 144,131,824
Service Classification No. 3	$ 1,129,983	$ 1,156,653	$ 858,443	$ 1,207,163	$ 1,053,093	$ 890,673	$ 944,883	$ 948,223	$ 840,143	$ 996,543	$ 1,009,733	$ 1,043,043	$ 12,078,576
Service Classification No. 5	$ 256,590	$ 257,650	$ 258,710	$ 260,460	$ 261,470	$ 262,890	$ 260,750	$ 258,330	$ 257,980	$ 256,610	$ 255,560	$ 254,540	$ 3,101,540
Service Classification No. 6	$ 245,310	$ 238,190	$ 244,970	$ 229,950	$ 203,550	$ 258,560	$ 259,210	$ 197,270	$ 215,550	$ 195,630	$ 215,940	$ 207,540	$ 2,711,670
Service Classification No. 8	$ 519,580	$ 519,630	$ 519,690	$ 519,790	$ 519,840	$ 519,920	$ 517,380	$ 517,240	$ 517,220	$ 517,140	$ 517,090	$ 517,030	$ 6,221,546
Service Classification No. 9	$ 18,560	$ 18,560	$ 18,780	$ 18,780	$ 18,780	$ 18,780	$ 18,780	$ 18,780	$ 18,780	$ 18,780	$ 18,780	$ 18,780	$ 224,920
Service Classification No. 13													
Transmission	$ 794,570	$ 767,000	$ 781,930	$ 769,830	$ 692,240	$ 701,050	$ 665,420	$ 668,740	$ 735,900	$ 717,840	$ 731,580	$ 766,430	$ 8,792,530
Substation	$ 251,263	$ 250,593	$ 316,733	$ 216,283	$ 231,483	$ 230,313	$ 202,753	$ 202,763	$ 202,633	$ 207,343	$ 207,643	$ 216,263	$ 2,736,066
	$ 1,045,833	$ 1,017,593	$ 1,098,663	$ 986,113	$ 923,723	$ 931,363	$ 868,173	$ 871,503	$ 938,533	$ 925,183	$ 939,223	$ 982,693	$ 11,528,596
Interdepartmental	$ 10,000	$ 9,480	$ 8,420	$ 6,840	$ 7,900	$ 8,420	$ 8,420	$ 7,370	$ 8,420	$ 7,900	$ 6,320	$ 6,840	$ 96,330
Total Base Revenue	$ 52,581,428	$ 52,134,898	$ 47,998,648	$ 45,410,248	$ 44,740,638	$ 47,486,778	$ 56,941,518	$ 54,598,608	$ 50,638,488	$ 46,243,958	$ 43,594,398	$ 43,448,368	$ 585,817,972

Appendix N Sheet 7 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Customers by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2026)

	July 2025	August 2025	September 2025	October 2025	November 2025	December 2025	January 2026	February 2026	March 2026	April 2026	May 2026	June 2026	Average
Service Classification No. 1													
Heating	38,345	37,731	35,910	36,144	35,848	35,316	37,834	36,853	38,004	38,645	39,468	42,168	37,689
Nonheating	241,591	230,882	240,929	240,814	237,504	226,242	239,003	228,472	231,319	230,114	232,124	224,878	233,656
	279,936	268,613	276,839	276,958	273,352	261,558	276,837	265,325	269,323	268,759	271,592	267,046	271,345
Service Classification No. 2													
Nondemand	34,136	34,978	33,704	36,672	35,210	34,142	36,381	34,084	35,789	34,460	35,740	34,558	34,988
Primary	149	143	131	177	162	130	151	152	157	165	155	148	152
Secondary	11,945	11,555	11,107	12,261	11,153	11,057	11,720	11,035	11,636	11,392	11,506	11,122	11,457
	46,230	46,676	44,942	49,110	46,525	45,329	48,252	45,271	47,582	46,017	47,401	45,828	46,597
Service Classification No. 3	37	37	37	37	37	37	37	37	37	37	37	37	37
Service Classification No. 5	3,840	3,840	3,840	3,840	3,840	3,840	3,786	3,786	3,786	3,786	3,786	3,786	3,813
Service Classification No. 6													
Heating	340	340	340	340	340	340	340	340	340	340	340	340	340
Nonheating	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
Service Classification No. 6	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Service Classification No. 8	212	212	212	212	212	212	212	212	212	212	212	212	212
Service Classification No. 9	59	59	59	59	59	59	58	58	58	58	58	58	59
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	6	6	6	6	6	6	4	4	4	4	4	4	5
	12	12	12	12	12	12	10	10	10	10	10	10	11
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	331,727	320,850	327,342	331,629	325,438	312,448	330,593	316,100	322,409	320,280	324,497	318,378	323,474

Appendix N Sheet 8 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Demand Determinants by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2026)

	July 2025	August 2025	September 2025	October 2025	November 2025	December 2025	January 2026	February 2026	March 2026	April 2026	May 2026	June 2026	Total
Service Classification No. 2													
Primary kW	52,848	48,363	47,539	57,434	43,626	42,052	44,005	45,068	41,529	40,811	46,719	40,527	550,521
Secondary kW	399,519	402,549	377,169	429,369	330,638	316,231	358,434	317,353	307,711	313,119	354,237	377,999	4,284,328
	452,367	450,912	424,708	486,803	374,264	358,283	402,439	362,421	349,240	353,930	400,956	418,526	4,834,849
Service Classification No. 3 kW	68,580	70,352	50,334	73,743	63,447	52,625	56,460	56,604	49,223	59,679	60,487	62,746	724,280
Service Classification No. 13													
Transmission kW	93,952	90,350	92,291	90,541	80,569	81,737	77,281	77,708	86,108	83,988	85,776	90,296	1,030,597
Substation kW	16,136	16,082	21,488	13,284	14,554	14,431	13,809	13,816	13,801	14,156	14,173	14,872	180,602
	110,088	106,432	113,779	103,825	95,123	96,168	91,090	91,524	99,909	98,144	99,949	105,168	1,211,199
Total kW	631,035	627,696	588,821	664,371	532,834	507,076	549,989	510,549	498,372	511,753	561,392	586,440	6,770,328
Service Classification No. 2 RkVa													
Primary RkVa	52,848	48,363	47,539	57,434	43,626	42,052	4,401	4,507	4,154	5,306	6,540	7,295	324,065
Secondary RkVa	17,363	14,304	14,110	12,385	9,091	6,488	7,755	8,200	7,732	10,013	11,837	12,543	131,821
	70,211	62,667	61,649	69,819	52,717	48,540	12,156	12,707	11,886	15,319	18,377	19,838	455,886
Service Classification No. 3 RkVa	9,088	9,511	7,648	9,868	8,073	5,579	2,408	3,874	5,452	7,215	8,667	8,437	85,820
Service Classification No. 13													
Transmission RkVa	4,180	4,330	4,350	5,970	4,900	4,690	3,050	3,090	6,190	4,070	4,050	4,160	53,030
Substation RkVa	2,470	2,470	2,310	2,450	2,010	2,400	1,770	1,700	1,750	2,180	2,290	2,340	26,140
	6,650	6,800	6,660	8,420	6,910	7,090	4,820	4,790	7,940	6,250	6,340	6,500	79,170
Total RkVa	85,949	78,978	75,957	88,107	67,700	61,209	19,384	21,371	25,278	28,784	33,384	34,775	620,876

Appendix N Sheet 9 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Sales (MWh) by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2027)

	July 2026	August 2026	September 2026	October 2026	November 2026	December 2026	January 2027	February 2027	March 2027	April 2027	May 2027	June 2027	Total
Service Classification No. 1													
Heating	15,547	16,459	15,806	21,088	40,525	57,692	88,426	91,604	78,852	60,696	35,111	20,068	541,874
Nonheating	183,024	194,679	173,004	141,330	135,504	144,242	173,286	162,910	146,097	132,329	129,482	139,667	1,855,555
	198,570	211,138	188,810	162,419	176,029	201,934	261,712	254,515	224,949	193,025	164,593	159,735	2,397,429
Service Classification No. 2													
Nondemand	16,062	16,585	14,917	15,717	17,879	19,911	23,439	22,349	21,708	18,629	16,369	15,013	218,579
Primary	20,183	19,545	19,547	21,840	17,951	17,403	19,509	18,066	18,334	15,566	17,729	17,800	223,473
Secondary	132,730	134,057	121,512	108,070	99,867	105,413	115,970	108,719	105,396	97,746	103,061	110,119	1,342,660
	168,975	170,187	155,976	145,627	135,698	142,727	158,918	149,134	145,439	131,940	137,158	142,933	1,784,711
Service Classification No. 3	31,339	30,340	22,202	32,262	26,723	23,286	26,421	25,384	23,409	27,269	26,471	27,451	322,559
Service Classification No. 5	750	830	920	1,060	1,150	1,260	1,190	990	960	850	760	680	11,400
Service Classification No. 6													
Heating	1,040	970	860	960	760	1,120	1,310	900	930	810	900	860	11,420
Nonheating	790	760	910	710	680	810	680	530	660	590	660	630	8,410
	1,830	1,730	1,770	1,670	1,440	1,930	1,990	1,430	1,590	1,400	1,560	1,490	19,830
Service Classification No. 8	710	790	870	1,010	1,090	1,200	1,140	950	930	820	740	650	10,900
Service Classification No. 9	60	60	60	60	60	60	60	60	60	60	60	60	720
Service Classification No. 13													
Transmission	58,910	57,260	53,180	52,080	49,700	48,810	48,880	45,340	50,040	50,580	52,460	53,720	620,960
Substation	9,460	9,500	8,730	8,800	8,410	8,140	9,120	7,630	8,840	8,530	8,720	8,910	104,790
	68,370	66,760	61,910	60,880	58,110	56,950	58,000	52,970	58,880	59,110	61,180	62,630	725,750
Interdepartmental	95	90	80	65	75	80	80	70	80	75	60	65	915
Total	470,699	481,925	432,599	405,053	400,375	429,427	509,511	485,503	456,297	414,549	392,582	395,694	5,274,214

Appendix N Sheet 10 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Base Delivery Revenues (Excluding Revenue Tax) by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2027)

	July 2026	August 2026	September 2026	October 2026	November 2026	December 2026	January 2027	February 2027	March 2027	April 2027	May 2027	June 2027	Total
Service Classification No. 1													
Heating	$ 3,389,420	$ 3,514,970	$ 3,375,240	$ 4,175,160	$ 7,079,910	$ 9,638,860	$ 14,301,530	$ 14,755,880	$ 12,877,190	$ 10,176,760	$ 6,370,400	$ 4,185,860	$ 93,841,180
Nonheating	$ 33,054,750	$ 34,527,370	$ 31,530,730	$ 26,788,550	$ 25,818,390	$ 26,865,030	$ 31,511,780	$ 29,694,520	$ 27,254,220	$ 25,167,020	$ 24,782,970	$ 26,121,980	$ 343,117,310
	$ 36,444,170	$ 38,042,340	$ 34,905,970	$ 30,963,710	$ 32,898,300	$ 36,503,890	$ 45,813,310	$ 44,450,400	$ 40,131,410	$ 35,343,780	$ 31,153,370	$ 30,307,840	$ 436,958,490
Service Classification No. 2													
Nondemand	$ 3,208,300	$ 3,268,050	$ 3,023,350	$ 3,240,680	$ 3,457,320	$ 3,670,050	$ 4,189,110	$ 3,964,760	$ 3,951,700	$ 3,515,760	$ 3,290,510	$ 3,077,990	$ 41,857,580
Primary	$ 784,118	$ 729,308	$ 711,868	$ 853,858	$ 669,488	$ 636,768	$ 668,928	$ 678,968	$ 635,868	$ 631,928	$ 700,338	$ 618,388	$ 8,319,826
Secondary	$ 9,488,854	$ 9,490,244	$ 8,908,694	$ 9,916,974	$ 8,028,794	$ 7,814,074	$ 8,698,264	$ 7,833,224	$ 7,761,834	$ 7,769,374	$ 8,480,904	$ 8,850,384	$ 103,041,618
	$ 13,481,272	$ 13,487,602	$ 12,643,912	$ 14,011,512	$ 12,155,602	$ 12,120,892	$ 13,556,302	$ 12,476,952	$ 12,349,402	$ 11,917,062	$ 12,471,752	$ 12,546,762	$ 153,219,024
Service Classification No. 3	$ 1,195,683	$ 1,227,883	$ 907,873	$ 1,274,703	$ 1,113,383	$ 945,533	$ 1,002,353	$ 1,002,123	$ 888,373	$ 1,052,963	$ 1,063,553	$ 1,098,933	$ 12,773,356
Service Classification No. 5	$ 270,860	$ 271,920	$ 272,980	$ 274,730	$ 275,740	$ 277,160	$ 275,620	$ 273,210	$ 272,850	$ 271,490	$ 270,430	$ 269,410	$ 3,276,400
Service Classification No. 6	$ 258,090	$ 250,640	$ 257,790	$ 241,960	$ 214,200	$ 272,020	$ 272,630	$ 207,560	$ 226,750	$ 205,840	$ 227,220	$ 218,390	$ 2,853,090
Service Classification No. 8	$ 542,651	$ 542,701	$ 542,761	$ 542,861	$ 542,911	$ 542,991	$ 541,871	$ 541,741	$ 541,721	$ 541,641	$ 541,591	$ 541,531	$ 6,506,970
Service Classification No. 9	$ 19,700	$ 19,700	$ 19,700	$ 19,700	$ 19,700	$ 19,700	$ 19,700	$ 19,700	$ 19,700	$ 19,700	$ 19,700	$ 19,700	$ 236,400
Service Classification No. 13													
Transmission	$ 848,280	$ 819,450	$ 835,060	$ 822,350	$ 741,280	$ 750,490	$ 713,310	$ 716,780	$ 786,880	$ 768,080	$ 782,430	$ 818,880	$ 9,403,270
Substation	$ 231,057	$ 230,347	$ 299,107	$ 194,737	$ 210,527	$ 209,357	$ 213,637	$ 213,667	$ 213,517	$ 218,407	$ 218,717	$ 227,667	$ 2,680,744
	$ 1,079,337	$ 1,049,797	$ 1,134,167	$ 1,017,087	$ 951,807	$ 959,847	$ 926,947	$ 930,447	$ 1,000,397	$ 986,487	$ 1,001,147	$ 1,046,547	$ 12,084,014
Interdepartmental	$ 10,000	$ 9,480	$ 8,420	$ 6,840	$ 7,900	$ 8,420	$ 8,420	$ 7,370	$ 8,420	$ 7,900	$ 6,320	$ 6,840	$ 96,330
Total Base Revenue	$ 53,301,763	$ 54,902,063	$ 50,693,573	$ 48,353,103	$ 48,179,543	$ 51,650,453	$ 62,417,153	$ 59,909,503	$ 55,439,023	$ 50,346,863	$ 46,755,083	$ 46,055,953	$ 628,004,074

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Customers by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2027)

	July 2026	August 2026	September 2026	October 2026	November 2026	December 2026	January 2027	February 2027	March 2027	April 2027	May 2027	June 2027	Average
Service Classification No. 1													
Heating	44,281	43,820	42,073	42,459	42,288	41,854	44,489	43,600	44,840	45,545	46,485	49,273	44,251
Nonheating	235,977	224,653	234,953	234,876	230,785	219,908	232,408	221,388	224,551	223,440	225,196	217,469	227,134
	280,258	268,473	277,026	277,335	273,073	261,762	276,897	264,988	269,391	268,985	271,681	266,742	271,384
Service Classification No. 2													
Nondemand	34,694	34,549	33,473	36,842	35,367	34,239	36,553	34,012	35,914	34,376	35,956	34,690	35,055
Primary	151	151	146	176	163	139	147	150	150	163	153	143	153
Secondary	11,990	11,597	11,148	12,309	11,200	11,095	11,766	11,079	11,677	11,429	11,543	11,162	11,500
	46,835	46,297	44,767	49,327	46,730	45,473	48,466	45,241	47,741	45,968	47,652	45,995	46,708
Service Classification No. 3	37	37	37	37	37	37	37	37	37	37	37	37	37
Service Classification No. 5	3,786	3,786	3,786	3,786	3,786	3,786	3,733	3,733	3,733	3,733	3,733	3,733	3,760
Service Classification No. 6													
Heating	340	340	340	340	340	340	340	340	340	340	340	340	340
Nonheating	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Service Classification No. 8	212	212	212	212	212	212	212	212	212	212	212	212	212
Service Classification No. 9	58	58	58	58	58	58	57	57	57	57	57	57	58
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	4	4	4	4	4	4	4	4	4	4	4	4	4
	10	10	10	10	10	10	10	10	10	10	10	10	10
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	332,597	320,274	327,297	332,166	325,307	312,739	330,813	315,679	322,582	320,403	324,783	318,187	323,569

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Demand Determinants by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2027)

	July 2026	August 2026	September 2026	October 2026	November 2026	December 2026	January 2027	February 2027	March 2027	April 2027	May 2027	June 2027	Total
Service Classification No. 2													
Primary kW	53,113	48,863	47,676	57,474	43,782	42,449	44,338	45,168	41,671	40,960	46,655	40,455	552,604
Secondary kW	402,208	406,232	379,730	432,279	332,895	319,427	362,410	319,765	309,982	315,310	355,384	379,724	4,315,346
	455,321	455,095	427,406	489,753	376,677	361,876	362,410	319,765	309,982	315,310	355,384	379,724	4,867,950
Service Classification No. 3 kW	68,864	70,905	50,494	73,889	63,641	53,014	56,829	56,737	49,361	59,820	60,420	62,700	726,674
Service Classification No. 13													
Transmission kW	94,952	91,350	93,291	91,541	81,569	82,737	78,281	78,708	87,108	84,988	86,776	91,296	1,042,597
Substation kW	15,136	15,082	20,488	12,284	13,554	13,431	13,809	13,816	13,801	14,156	14,173	14,872	174,602
	110,088	106,432	113,779	103,825	95,123	96,168	92,090	92,524	100,909	99,144	100,949	106,168	1,217,199
Total kW	634,273	632,432	591,679	667,467	535,441	511,058	511,329	469,026	460,252	474,274	516,753	548,592	6,811,823
Service Classification No. 2 RkVa													
Primary RkVa	8,497	6,840	7,152	6,323	4,379	3,396	4,434	4,518	4,168	5,324	6,532	7,282	68,845
Secondary RkVa	17,480	14,435	14,207	12,469	9,154	6,554	7,841	8,263	7,789	10,083	11,876	12,602	132,753
	25,977	21,275	21,359	18,792	13,533	9,950	12,275	12,781	11,957	15,407	18,408	19,884	201,598
Service Classification No. 3 RkVa	9,130	9,594	7,676	9,890	8,101	5,626	2,426	3,884	5,470	7,235	8,656	8,430	86,118
Service Classification No. 13													
Transmission RkVa	4,180	4,330	4,350	5,970	4,900	4,690	3,050	3,090	6,190	4,070	4,050	4,160	53,030
Substation RkVa	2,380	2,360	2,230	2,390	1,920	2,400	1,770	1,700	1,750	2,180	2,290	2,340	25,710
	6,560	6,690	6,580	8,360	6,820	7,090	4,820	4,790	7,940	6,250	6,340	6,500	78,740
Total RkVa	41,667	37,559	35,615	37,042	28,454	22,666	19,521	21,455	25,367	28,892	33,404	34,814	366,456

Appendix N Sheet 13 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Sales (MWh) by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2028)

	July 2027	August 2027	September 2027	October 2027	November 2027	December 2027	January 2028	February 2028	March 2028	April 2028	May 2028	June 2028	Total
Service Classification No. 1													
Heating	14,985	15,645	16,147	23,386	47,691	68,784	104,606	108,535	93,131	71,385	40,398	21,521	626,215
Nonheating	183,611	195,451	173,782	142,373	136,805	145,397	174,777	164,871	147,595	133,719	131,094	140,666	1,870,142
	198,596	211,096	189,930	165,759	184,496	214,181	279,384	273,405	240,726	205,104	171,492	162,187	2,496,357
Service Classification No. 2													
Nondemand	16,080	16,765	15,105	16,037	18,532	20,961	24,880	23,862	22,990	19,600	16,887	15,230	226,930
Primary	20,209	19,635	19,602	21,843	17,994	17,481	19,536	18,135	18,395	15,619	17,778	17,784	224,013
Secondary	133,298	134,919	122,296	108,636	100,498	106,222	116,665	109,754	106,309	98,594	103,919	110,660	1,351,771
	169,588	171,320	157,004	146,516	137,024	144,665	161,082	151,751	147,695	133,814	138,583	143,674	1,802,714
Service Classification No. 3	31,372	30,445	22,252	32,281	26,768	23,367	26,447	25,469	23,473	27,335	26,532	27,434	323,176
Service Classification No. 5	740	820	910	1,050	1,130	1,250	1,180	980	950	840	760	670	11,280
Service Classification No. 6													
Heating	1,040	970	860	960	760	1,120	1,310	900	930	810	900	860	11,420
Nonheating	790	760	910	710	680	810	680	530	660	590	660	630	8,410
	1,830	1,730	1,770	1,670	1,440	1,930	1,990	1,430	1,590	1,400	1,560	1,490	19,830
Service Classification No. 8	710	790	870	1,010	1,090	1,200	1,140	950	930	820	740	650	10,900
Service Classification No. 9	60	60	60	60	60	60	60	60	60	60	60	60	720
Service Classification No. 13													
Transmission	58,910	57,260	53,180	52,080	49,700	48,810	48,880	45,340	50,040	50,580	52,460	53,720	620,960
Substation	9,460	9,500	8,730	8,800	8,410	8,140	9,120	7,630	8,840	8,530	8,720	8,910	104,790
	68,370	66,760	61,910	60,880	58,110	56,950	58,000	52,970	58,880	59,110	61,180	62,630	725,750
Interdepartmental	95	90	80	65	75	80	80	70	80	75	60	65	915
Total	471,362	483,111	434,785	409,291	410,193	443,682	529,362	507,086	474,385	428,558	400,967	398,860	5,391,642

Appendix N Sheet 14 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Base Delivery Revenues (Excluding Revenue Tax) by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2028)

	July 2027	August 2027	September 2027	October 2027	November 2027	December 2027	January 2028	February 2028	March 2028	April 2028	May 2028	June 2028	Total
Service Classification No. 1													
Heating	$ 3,633,340	$ 3,724,760	$ 3,759,320	$ 4,879,720	$ 8,600,160	$ 11,822,510	$ 17,379,230	$ 17,960,130	$ 15,636,450	$ 12,325,690	$ 7,606,680	$ 4,791,080	$ 112,119,070
Nonheating	$ 34,072,790	$ 35,587,820	$ 32,528,330	$ 27,718,060	$ 26,767,100	$ 27,783,090	$ 32,611,920	$ 30,812,750	$ 28,235,240	$ 26,081,620	$ 25,733,160	$ 26,981,150	$ 354,913,030
Unbilled													
	$ 37,706,130	$ 39,312,580	$ 36,287,650	$ 32,597,780	$ 35,367,260	$ 39,605,600	$ 49,991,150	$ 48,772,880	$ 43,871,690	$ 38,407,310	$ 33,339,840	$ 31,772,230	$ 467,032,100
Service Classification No. 2													
Nondemand	$ 3,318,590	$ 3,413,620	$ 3,160,240	$ 3,397,680	$ 3,660,100	$ 3,926,270	$ 4,508,170	$ 4,288,030	$ 4,245,210	$ 3,761,560	$ 3,472,150	$ 3,215,980	$ 44,367,600
Primary	$ 810,615	$ 752,395	$ 728,515	$ 883,505	$ 693,405	$ 655,775	$ 692,518	$ 704,418	$ 659,528	$ 655,908	$ 726,538	$ 638,968	$ 8,602,088
Secondary	$ 9,834,383	$ 9,845,853	$ 9,247,283	$ 10,283,313	$ 8,352,613	$ 8,141,133	$ 9,039,594	$ 8,170,024	$ 8,102,354	$ 8,107,374	$ 8,829,974	$ 9,176,054	$ 107,129,952
	$ 13,963,588	$ 14,011,868	$ 13,136,038	$ 14,564,498	$ 12,706,118	$ 12,723,178	$ 14,240,282	$ 13,162,472	$ 13,007,092	$ 12,524,842	$ 13,028,662	$ 13,031,002	$ 160,099,640
Service Classification No. 3	$ 1,236,880	$ 1,272,850	$ 941,710	$ 1,317,590	$ 1,152,840	$ 981,580	$ 1,038,003	$ 1,039,953	$ 922,033	$ 1,091,433	$ 1,102,183	$ 1,135,673	$ 13,232,728
Service Classification No. 5	$ 279,550	$ 280,600	$ 281,650	$ 283,370	$ 284,380	$ 285,770	$ 285,200	$ 282,810	$ 282,460	$ 281,110	$ 280,060	$ 279,060	$ 3,386,020
Service Classification No. 6	$ 266,610	$ 258,980	$ 266,330	$ 250,080	$ 221,610	$ 280,940	$ 281,530	$ 214,780	$ 234,470	$ 213,010	$ 234,960	$ 225,910	$ 2,949,210
Service Classification No. 8	$ 559,031	$ 559,081	$ 559,141	$ 559,241	$ 559,291	$ 559,371	$ 558,941	$ 558,811	$ 558,791	$ 558,711	$ 558,661	$ 558,601	$ 6,707,670
Service Classification No. 9	$ 20,340	$ 20,340	$ 20,340	$ 20,340	$ 20,340	$ 20,140	$ 20,090	$ 20,290	$ 20,290	$ 20,290	$ 20,290	$ 20,290	$ 243,380
Service Classification No. 13													
Transmission	$ 884,760	$ 855,530	$ 871,360	$ 858,440	$ 776,270	$ 785,630	$ 748,070	$ 751,580	$ 822,610	$ 803,580	$ 818,130	$ 855,070	$ 9,831,030
Substation	$ 238,661	$ 237,961	$ 307,431	$ 201,981	$ 217,931	$ 216,761	$ 221,237	$ 221,267	$ 221,127	$ 226,047	$ 226,357	$ 235,397	$ 2,772,158
	$ 1,123,421	$ 1,093,491	$ 1,178,791	$ 1,060,421	$ 994,201	$ 1,002,391	$ 969,307	$ 972,847	$ 1,043,737	$ 1,029,627	$ 1,044,487	$ 1,090,467	$ 12,603,188
Interdepartmental	$ 10,000	$ 9,480	$ 8,420	$ 6,840	$ 7,900	$ 8,420	$ 8,420	$ 7,370	$ 8,420	$ 7,900	$ 6,320	$ 6,840	$ 96,330
Total Base Revenue	$ 55,165,550	$ 56,819,270	$ 52,680,070	$ 50,660,160	$ 51,313,940	$ 55,467,390	$ 67,392,923	$ 65,032,213	$ 59,948,983	$ 54,134,233	$ 49,615,463	$ 48,120,073	$ 666,350,266

Appendix N Sheet 15 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Customers by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2028)

	July 2027	August 2027	September 2027	October 2027	November 2027	December 2027	January 2028	February 2028	March 2028	April 2028	May 2028	June 2028	Average
Service Classification No. 1													
Heating	51,475	51,103	49,471	49,919	49,836	49,517	52,219	51,423	52,784	53,556	54,589	57,497	51,949
Nonheating	228,881	217,407	227,378	227,391	223,616	212,082	224,734	213,888	216,523	215,429	217,493	209,102	219,494
	280,356	268,510	276,849	277,310	273,452	261,599	276,953	265,311	269,307	268,985	272,082	266,599	271,443
Service Classification No. 2													
Nondemand	34,595	34,818	33,658	36,885	35,430	34,300	36,598	34,136	35,968	34,508	35,984	34,736	35,135
Primary	150	144	132	177	162	131	147	150	150	163	154	143	150
Secondary	12,021	11,638	11,189	12,339	11,225	11,131	11,790	11,106	11,699	11,458	11,563	11,179	11,528
	46,766	46,600	44,979	49,401	46,817	45,562	48,535	45,392	47,817	46,129	47,701	46,058	46,813
Service Classification No. 3	37	37	37	37	37	37	37	37	37	37	37	37	37
Service Classification No. 5	3,733	3,733	3,733	3,733	3,733	3,733	3,681	3,681	3,681	3,681	3,681	3,681	3,707
Service Classification No. 6													
Heating	340	340	340	340	340	340	340	340	340	340	340	340	340
Nonheating	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060
	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Service Classification No. 8	212	212	212	212	212	212	212	212	212	212	212	212	212
Service Classification No. 9	57	57	57	57	57	57	56	56	56	56	56	56	57
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	4	4	4	4	4	4	4	4	4	4	4	4	4
	10	10	10	10	10	10	10	10	10	10	10	10	10
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	332,572	320,560	327,278	332,161	325,719	312,611	330,885	316,100	322,521	320,511	325,180	318,054	323,679

Appendix N Sheet 16 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Electric Demand Determinants by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2028)

	July 2027	August 2027	September 2027	October 2027	November 2027	December 2027	January 2028	February 2028	March 2028	April 2028	May 2028	June 2028	Total
Service Classification No. 2													
Primary kW	53,184	49,091	47,810	57,484	43,888	42,637	44,402	45,339	41,807	41,102	46,782	40,416	553,942
Secondary kW	403,934	408,846	382,175	434,549	334,993	321,882	364,582	322,804	312,677	318,043	358,342	381,591	4,344,418
	457,118	457,937	429,985	492,033	378,881	364,519	408,984	368,143	354,484	359,145	405,124	422,007	4,898,360
Service Classification No. 3 kW	68,939	71,156	50,609	73,931	63,752	53,202	56,884	56,930	49,496	59,966	60,562	62,662	728,089
Service Classification No. 13													
Transmission kW	95,952	92,350	94,291	92,541	82,569	83,737	79,281	79,708	88,108	85,988	87,776	92,296	1,054,597
Substation kW	15,136	15,082	20,488	12,284	13,554	13,431	13,809	13,816	13,801	14,156	14,173	14,872	174,602
	111,088	107,432	114,779	104,825	96,123	97,168	93,090	93,524	101,909	100,144	101,949	107,168	1,229,199
Total kW	637,145	636,525	595,373	670,789	538,756	514,889	558,958	518,597	505,889	519,255	567,635	591,837	6,855,648
Service Classification No. 2 RkVa													
Primary RkVa	8,510	6,872	7,171	6,323	4,390	3,411	4,440	4,534	4,181	5,343	6,549	7,275	68,999
Secondary RkVa	17,555	14,527	14,298	12,534	9,211	6,603	7,889	8,342	7,856	10,170	11,974	12,663	133,622
	26,065	21,399	21,469	18,857	13,601	10,014	7,889	12,876	12,037	15,513	18,523	19,938	202,621
Service Classification No. 3 RkVa	9,141	9,632	7,696	9,896	8,116	5,649	2,429	3,899	5,487	7,255	8,679	8,424	86,303
Service Classification No. 13													
Transmission RkVa	4,180	4,330	4,350	5,970	4,900	4,690	3,050	3,090	6,190	4,070	4,050	4,160	53,030
Substation RkVa	2,380	2,360	2,230	2,390	1,920	2,400	1,770	1,700	1,750	2,180	2,290	2,340	25,710
	6,560	6,690	6,580	8,360	6,820	7,090	4,820	4,790	7,940	6,250	6,340	6,500	78,740
Total RkVa	41,766	37,721	35,745	37,113	28,537	22,753	15,138	21,565	25,464	29,018	33,542	34,862	367,664

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Gas Sales, Base Revenues and Customers By Service Classification
12 Months Ended June 30, 2026, June 30, 2027 & June 30, 2028

	12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year 3
Sales & Transport (Mcf)			
Service Classification Nos. 1 & 12			
Heat	5,399,248	5,372,613	5,344,954
Nonheating	168,919	172,574	176,965
	5,568,167	5,545,187	5,521,919
Service Classification Nos. 2, 6 & 13			
Heat	6,966,479	6,879,002	6,810,297
Nonheating	880,761	883,332	886,224
	7,847,240	7,762,334	7,696,521
Service Classification No. 8	167,062	167,062	167,062
Service Classification No. 9	3,927,468	3,927,468	3,927,468
Service Classification No. 11	2,267,132	2,267,132	2,267,132
Service Classification No. 14	-	-	-
Sales for Resale	-	-	-
Interdepartmental	22,680	22,680	22,680
Total Sales & Transport	19,799,748	19,691,862	19,602,781
Base Revenue ($)			
Service Classification Nos. 1 & 12			
Heat	$ 104,374,550	$ 111,737,730	$ 120,583,440
Nonheating	$ 5,091,620	$ 5,810,690	$ 6,748,280
	$ 109,466,170	$ 117,548,420	$ 127,331,720
Service Classification Nos. 2, 6 & 13			
Heat	$ 59,227,300	$ 62,899,030	$ 67,644,930
Nonheating	$ 7,404,510	$ 8,034,230	$ 8,811,680
	$ 66,631,810	$ 70,933,260	$ 76,456,610
Service Classification No. 8	$ 451,790	$ 277,580	$ 277,580
Service Classification No. 9	$ 2,347,230	$ 2,522,540	$ 2,522,540
Service Classification No. 11	$ 6,370,790	$ 6,370,790	$ 6,370,790
Service Classification No. 14	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -
Interdepartmental	$ 174,795	$ 188,661	$ 206,025
Total Own Territory	$ 185,442,585	$ 197,841,252	$ 213,165,265
Customers			
Service Classification Nos. 1 & 12			
Heat	68,430	67,632	66,629
Nonheating	8,323	9,309	10,472
	76,753	76,941	77,101
Service Classification Nos. 2, 6 & 13			
Heat	11,153	11,005	10,874
Nonheating	1,245	1,329	1,424
	12,398	12,334	12,298
Service Classification No. 8	8	8	8
Service Classification No. 9	25	25	25
Service Classification No. 11	9	9	9
Interdepartmental	1	1	1
Total Sales & Transport Customers	89,194	89,319	89,441

Appendix N Sheet 18 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Gas Customers & Sales by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2026)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	53,520	41,062	74,487	209,588	473,400	740,455	923,123	957,701	831,118	630,016	330,350	134,428	5,399,248
Nonheating	6,548	6,315	6,956	9,462	14,564	19,512	23,027	23,544	21,299	17,375	11,994	8,323	168,919
	60,068	47,377	81,443	219,050	487,964	759,967	946,150	981,245	852,417	647,391	342,344	142,751	5,568,167
Service Classification Nos. 2, 6 & 13													
Heat	185,827	169,165	210,046	338,560	611,505	871,293	1,064,443	1,080,177	970,240	734,392	464,088	266,743	6,966,479
Nonheating	46,935	44,127	47,096	61,954	72,648	93,541	107,892	113,356	89,684	88,966	63,938	50,624	880,761
	232,762	213,292	257,142	400,514	684,153	964,834	1,172,335	1,193,533	1,059,924	823,358	528,026	317,367	7,847,240
Service Classification No. 8	5,690	4,020	4,680	9,790	18,310	21,242	25,500	23,040	23,760	14,500	9,280	7,250	167,062
Service Classification No. 9	403,870	408,530	367,440	444,710	369,380	353,488	189,420	135,840	121,550	281,640	424,520	427,080	3,927,468
Service Classification No. 11	136,342	79,538	114,658	155,626	239,115	267,448	310,609	276,732	256,871	188,175	147,462	94,556	2,267,132
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	240	150	170	440	1,290	2,470	4,120	5,420	4,290	2,580	1,200	310	22,680
Total Sales & Transport	838,972	752,907	825,533	1,230,130	1,800,212	2,369,448	2,648,134	2,615,810	2,318,812	1,957,644	1,452,832	989,314	19,799,748
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat	$ 2,519,720	$ 2,327,660	$ 2,833,960	$ 4,935,640	$ 9,061,590	$ 13,234,780	$ 16,091,450	$ 16,629,230	$ 14,655,770	$ 11,523,760	$ 6,810,340	$ 3,750,650	$ 104,374,550
Nonheating	$ 298,290	$ 295,260	$ 307,100	$ 347,190	$ 429,010	$ 507,790	$ 563,600	$ 574,090	$ 541,390	$ 482,180	$ 400,650	$ 345,070	$ 5,091,620
	$ 2,818,010	$ 2,622,920	$ 3,141,060	$ 5,282,830	$ 9,490,600	$ 13,742,570	$ 16,655,050	$ 17,203,320	$ 15,197,160	$ 12,005,940	$ 7,210,990	$ 4,095,720	$ 109,466,170
Service Classification Nos. 2, 6 & 13													
Heat	$ 1,908,400	$ 1,767,350	$ 2,085,160	$ 3,068,910	$ 5,178,640	$ 7,178,920	$ 8,674,130	$ 8,788,660	$ 7,930,760	$ 6,077,940	$ 4,048,260	$ 2,520,170	$ 59,227,300
Nonheating	$ 413,520	$ 387,650	$ 415,140	$ 530,890	$ 611,850	$ 772,480	$ 883,730	$ 922,840	$ 743,540	$ 736,290	$ 545,220	$ 441,360	$ 7,404,510
	$ 2,321,920	$ 2,155,000	$ 2,500,300	$ 3,599,800	$ 5,790,490	$ 7,951,400	$ 9,557,860	$ 9,711,500	$ 8,674,300	$ 6,814,230	$ 4,593,480	$ 2,961,530	$ 66,631,810
Service Classification No. 8	$ 15,170	$ 11,620	$ 13,370	$ 27,130	$ 48,690	$ 57,730	$ 68,860	$ 62,300	$ 63,690	$ 39,320	$ 24,930	$ 18,980	$ 451,790
Service Classification No. 9	$ 208,680	$ 214,430	$ 189,460	$ 243,760	$ 204,740	$ 170,180	$ 179,270	$ 149,700	$ 148,040	$ 176,730	$ 237,000	$ 225,240	$ 2,347,230
Service Classification No. 11	$ 508,108	$ 495,258	$ 504,858	$ 519,568	$ 547,828	$ 558,508	$ 573,628	$ 561,808	$ 556,298	$ 529,588	$ 515,758	$ 499,588	$ 6,370,790
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 1,850	$ 1,156	$ 1,310	$ 3,391	$ 9,942	$ 19,036	$ 31,753	$ 41,772	$ 33,063	$ 19,884	$ 9,248	$ 2,389	$ 174,795
Total Own Territory	$ 5,873,737	$ 5,500,384	$ 6,350,358	$ 9,676,479	$ 16,092,290	$ 22,499,424	$ 27,066,420	$ 27,730,399	$ 24,672,551	$ 19,585,692	$ 12,591,406	$ 7,803,447	$ 185,442,585
Customers													
Service Classification Nos. 1 & 12													
Heat	68,635	68,448	68,575	68,461	68,508	68,340	68,303	68,216	68,521	69,202	67,971	67,977	68,430
Nonheating	7,956	8,006	8,090	8,156	8,234	8,281	8,310	8,391	8,481	8,571	8,659	8,742	8,323
	76,591	76,454	76,665	76,617	76,742	76,621	76,613	76,607	77,001	77,773	76,630	76,719	76,753
Service Classification Nos. 2, 6 & 13													
Heat	11,470	11,188	11,352	11,101	11,259	11,193	11,367	11,214	10,977	10,112	11,383	11,220	11,153
Nonheating	1,250	1,161	1,263	1,307	1,245	1,238	1,253	1,218	1,260	1,262	1,258	1,231	1,245
	12,720	12,349	12,615	12,408	12,504	12,431	12,619	12,432	12,236	11,374	12,640	12,451	12,398
Service Classification No. 8	8	8	8	8	8	8	8	8	8	8	8	8	8
Service Classification No. 9	25	25	25	25	25	25	25	25	25	25	25	25	25
Service Classification No. 11	9	9	9	9	9	9	9	9	9	9	9	9	9
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	89,354	88,846	89,323	89,068	89,289	89,095	89,275	89,082	89,280	89,190	89,313	89,213	89,194

Appendix N Sheet 19 of 20

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Gas Customers & Sales by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2027)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	50,563	38,213	71,572	207,305	471,392	739,338	921,647	956,466	829,187	627,732	327,617	131,581	5,372,613
Nonheating	6,767	6,548	7,183	9,719	14,846	19,846	23,407	23,952	21,678	17,730	12,298	8,600	172,574
	57,330	44,761	78,755	217,024	486,238	759,184	945,054	980,418	850,865	645,462	339,915	140,181	5,545,187
Service Classification Nos. 2, 6 & 13													
Heat	185,336	170,904	203,142	333,992	600,678	865,212	1,050,339	1,073,084	957,820	726,438	453,815	258,242	6,879,002
Nonheating	46,617	44,471	47,503	61,216	72,852	94,043	107,576	114,368	90,046	88,833	64,307	51,500	883,332
	231,953	215,375	250,645	395,208	673,530	959,255	1,157,915	1,187,452	1,047,866	815,271	518,122	309,742	7,762,334
Service Classification No. 8	5,690	4,020	4,680	9,790	18,310	21,242	25,500	23,040	23,760	14,500	9,280	7,250	167,062
Service Classification No. 9	403,870	408,530	367,440	444,710	369,380	353,488	189,420	135,840	121,550	281,640	424,520	427,080	3,927,468
Service Classification No. 11	136,342	79,538	114,658	155,626	239,115	267,448	310,609	276,732	256,871	188,175	147,462	94,556	2,267,132
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	240	150	170	440	1,290	2,470	4,120	5,420	4,290	2,580	1,200	310	22,680
Total Sales & Transport	835,425	752,374	816,348	1,222,798	1,787,863	2,363,086	2,632,618	2,608,902	2,305,202	1,947,628	1,440,499	979,119	19,691,862
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat	$ 2,610,320	$ 2,409,230	$ 2,949,140	$ 5,237,800	$ 9,709,090	$ 14,245,100	$ 17,331,350	$ 17,918,310	$ 15,767,370	$ 12,367,720	$ 7,254,260	$ 3,938,040	$ 111,737,730
Nonheating	$ 343,880	$ 341,440	$ 354,370	$ 398,820	$ 488,170	$ 575,100	$ 636,870	$ 649,070	$ 613,470	$ 549,280	$ 460,260	$ 399,960	$ 5,810,690
	$ 2,954,200	$ 2,750,670	$ 3,303,510	$ 5,636,620	$ 10,197,260	$ 14,820,200	$ 17,968,220	$ 18,567,380	$ 16,380,840	$ 12,917,000	$ 7,714,520	$ 4,338,000	$ 117,548,420
Service Classification Nos. 2, 6 & 13													
Heat	$ 2,027,300	$ 1,902,540	$ 2,164,070	$ 3,252,290	$ 5,471,220	$ 7,675,020	$ 9,217,320	$ 9,404,150	$ 8,430,510	$ 6,472,360	$ 4,256,970	$ 2,625,280	$ 62,899,030
Nonheating	$ 444,710	$ 423,310	$ 453,470	$ 567,580	$ 663,670	$ 839,770	$ 952,640	$ 1,006,640	$ 807,360	$ 795,120	$ 593,640	$ 486,320	$ 8,034,230
	$ 2,472,010	$ 2,325,850	$ 2,617,540	$ 3,819,870	$ 6,134,890	$ 8,514,790	$ 10,169,960	$ 10,410,790	$ 9,237,870	$ 7,267,480	$ 4,850,610	$ 3,111,600	$ 70,933,260
Service Classification No. 8	$ 9,360	$ 6,970	$ 8,050	$ 16,490	$ 30,260	$ 35,590	$ 42,260	$ 38,220	$ 39,180	$ 24,100	$ 15,330	$ 11,770	$ 277,580
Service Classification No. 9	$ 219,680	$ 225,950	$ 199,910	$ 260,050	$ 220,760	$ 182,810	$ 199,320	$ 167,860	$ 165,920	$ 190,740	$ 252,020	$ 237,520	$ 2,522,540
Service Classification No. 11	$ 508,108	$ 495,258	$ 504,858	$ 519,568	$ 547,828	$ 558,508	$ 573,628	$ 561,808	$ 556,298	$ 529,588	$ 515,758	$ 499,588	$ 6,370,790
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 1,996	$ 1,248	$ 1,414	$ 3,660	$ 10,731	$ 20,546	$ 34,272	$ 45,086	$ 35,686	$ 21,461	$ 9,982	$ 2,579	$ 188,661
Total Own Territory	$ 6,165,354	$ 5,805,945	$ 6,635,282	$ 10,256,258	$ 17,141,728	$ 24,132,444	$ 28,987,659	$ 29,791,143	$ 26,415,793	$ 20,950,369	$ 13,358,220	$ 8,201,056	$ 197,841,252
Customers													
Service Classification Nos. 1 & 12													
Heat	67,940	67,894	67,830	67,788	67,732	67,578	67,460	67,382	67,638	68,296	67,022	67,027	67,632
Nonheating	8,837	8,918	9,011	9,103	9,193	9,265	9,312	9,410	9,511	9,618	9,717	9,817	9,309
	76,777	76,812	76,840	76,891	76,925	76,843	76,772	76,792	77,149	77,914	76,739	76,843	76,941
Service Classification Nos. 2, 6 & 13													
Heat	11,258	11,172	11,113	11,018	11,046	11,100	11,170	11,114	10,797	9,999	11,195	11,082	11,005
Nonheating	1,318	1,249	1,354	1,369	1,326	1,324	1,328	1,311	1,346	1,342	1,348	1,336	1,329
	12,575	12,421	12,466	12,387	12,371	12,424	12,498	12,425	12,143	11,341	12,543	12,417	12,334
Service Classification No. 8	8	8	8	8	8	8	8	8	8	8	8	8	8
Service Classification No. 9	25	25	25	25	25	25	25	25	25	25	25	25	25
Service Classification No. 11	9	9	9	9	9	9	9	9	9	9	9	9	9
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	89,395	89,276	89,349	89,321	89,339	89,310	89,313	89,260	89,335	89,298	89,325	89,303	89,319

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Gas Customers & Sales by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2028)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	47,497	35,130	68,591	204,663	469,017	737,585	920,074	954,806	827,462	625,923	325,286	128,920	5,344,954
Nonheating	7,026	6,811	7,455	10,024	15,209	20,271	23,875	24,439	22,140	18,150	12,653	8,912	176,965
	54,523	41,941	76,046	214,687	484,226	757,856	943,949	979,245	849,602	644,073	337,939	137,832	5,521,919
Service Classification Nos. 2, 6 & 13													
Heat	175,813	161,973	196,874	328,446	593,850	859,653	1,043,217	1,068,123	952,465	723,072	450,674	256,137	6,810,297
Nonheating	46,370	44,878	47,796	60,869	73,223	94,380	107,486	115,201	90,230	88,936	64,709	52,146	886,224
	222,183	206,851	244,670	389,315	667,073	954,033	1,150,703	1,183,324	1,042,695	812,008	515,383	308,283	7,696,521
Service Classification No. 8	5,690	4,020	4,680	9,790	18,310	21,242	25,500	23,040	23,760	14,500	9,280	7,250	167,062
Service Classification No. 9	403,870	408,530	367,440	444,710	369,380	353,488	189,420	135,840	121,550	281,640	424,520	427,080	3,927,468
Service Classification No. 11	136,342	79,538	114,658	155,626	239,115	267,448	310,609	276,732	256,871	188,175	147,462	94,556	2,267,132
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	240	150	170	440	1,290	2,470	4,120	5,420	4,290	2,580	1,200	310	22,680
Total Sales & Transport	822,848	741,030	807,664	1,214,568	1,779,394	2,356,536	2,624,301	2,603,601	2,298,768	1,942,976	1,435,784	975,311	19,602,781
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat	$ 2,714,910	$ 2,492,510	$ 3,085,830	$ 5,596,150	$ 10,483,560	$ 15,447,510	$ 18,819,440	$ 19,458,340	$ 17,109,390	$ 13,396,550	$ 7,804,760	$ 4,174,490	$ 120,583,440
Nonheating	$ 407,030	$ 405,110	$ 419,160	$ 467,370	$ 565,170	$ 661,060	$ 729,630	$ 743,910	$ 704,940	$ 634,840	$ 537,410	$ 472,650	$ 6,748,280
	$ 3,121,940	$ 2,897,620	$ 3,504,990	$ 6,063,520	$ 11,048,730	$ 16,108,570	$ 19,549,070	$ 20,202,250	$ 17,814,330	$ 14,031,390	$ 8,342,170	$ 4,647,140	$ 127,331,720
Service Classification Nos. 2, 6 & 13													
Heat	$ 2,088,830	$ 1,960,730	$ 2,270,290	$ 3,466,960	$ 5,877,150	$ 8,296,590	$ 9,965,460	$ 10,190,290	$ 9,123,690	$ 7,006,150	$ 4,585,240	$ 2,813,550	$ 67,644,930
Nonheating	$ 483,660	$ 467,280	$ 498,730	$ 616,880	$ 729,130	$ 921,130	$ 1,040,300	$ 1,108,260	$ 884,310	$ 870,200	$ 653,250	$ 538,550	$ 8,811,680
	$ 2,572,490	$ 2,428,010	$ 2,769,020	$ 4,083,840	$ 6,606,280	$ 9,217,720	$ 11,005,760	$ 11,298,550	$ 10,008,000	$ 7,876,350	$ 5,238,490	$ 3,352,100	$ 76,456,610
Service Classification No. 8	$ 9,360	$ 6,970	$ 8,050	$ 16,490	$ 30,260	$ 35,590	$ 42,260	$ 38,220	$ 39,180	$ 24,100	$ 15,330	$ 11,770	$ 277,580
Service Classification No. 9	$ 219,680	$ 225,950	$ 199,910	$ 260,050	$ 220,760	$ 182,810	$ 199,320	$ 167,860	$ 165,920	$ 190,740	$ 252,020	$ 237,520	$ 2,522,540
Service Classification No. 11	$ 508,108	$ 495,258	$ 504,858	$ 519,568	$ 547,828	$ 558,508	$ 573,628	$ 561,808	$ 556,298	$ 529,588	$ 515,758	$ 499,588	$ 6,370,790
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 2,180	$ 1,363	$ 1,544	$ 3,997	$ 11,718	$ 22,437	$ 37,426	$ 49,235	$ 38,970	$ 23,437	$ 10,901	$ 2,816	$ 206,025
Total Own Territory	$ 6,433,758	$ 6,055,170	$ 6,988,372	$10,947,464	$ 18,465,576	$ 26,125,635	$ 31,407,464	$ 32,317,923	$ 28,622,698	$ 22,675,604	$ 14,374,668	$ 8,750,934	$ 213,165,265
Customers													
Service Classification Nos. 1 & 12													
Heat	66,964	66,897	66,845	66,796	66,722	66,591	66,457	66,367	66,623	67,284	65,995	66,003	66,629
Nonheating	9,922	10,018	10,124	10,230	10,334	10,419	10,481	10,594	10,709	10,830	10,944	11,059	10,472
	76,886	76,915	76,969	77,026	77,056	77,010	76,938	76,961	77,332	78,114	76,939	77,061	77,101
Service Classification Nos. 2, 6 & 13													
Heat	11,060	11,019	10,954	10,899	10,903	10,988	11,038	11,006	10,674	9,894	11,077	10,978	10,874
Nonheating	1,396	1,348	1,448	1,449	1,421	1,419	1,417	1,414	1,441	1,437	1,449	1,445	1,424
	12,456	12,367	12,402	12,348	12,324	12,407	12,455	12,420	12,115	11,331	12,526	12,423	12,298
Service Classification No. 8	8	8	8	8	8	8	8	8	8	8	8	8	8
Service Classification No. 9	25	25	25	25	25	25	25	25	25	25	25	25	25
Service Classification No. 11	9	9	9	9	9	9	9	9	9	9	9	9	9
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	89,385	89,325	89,414	89,417	89,423	89,460	89,436	89,424	89,490	89,488	89,508	89,527	89,441

Appendix O Sheet 1 of 12

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Billing Determinants
(Excludes S.C. Nos. 5 & 8, Unbilled & Interdepartmental)

		12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year 3
S.C. No. 1				
	Customer Months	3,256,138	3,256,611	3,257,313
	kWh	2,327,495,585	2,397,429,341	2,496,356,763
S.C. No. 2 - Non-Demand				
	Customer Months	419,854	420,665	421,616
	kWh	211,668,053	218,578,796	226,930,488
S.C. No. 2 - Secondary				
	Customer Months	137,489	137,995	138,338
	kWh	1,332,903,225	1,342,659,624	1,351,770,804
	kW	4,284,328	4,315,346	4,344,418
	Rkva	131,821	132,753	133,622
S.C. No. 2 - Primary				
	Customer Months	1,820	1,832	1,803
	kWh	222,628,098	223,472,623	224,012,907
	kW	550,521	552,604	553,942
	Rkva	68,605	68,845	68,999
S.C. No. 3				
	Customer Months	468	468	468
	kWh	321,512,000	322,558,548	323,175,706
	kW	724,280	726,674	728,089
	Rkva	85,820	86,118	86,303
S.C. No. 6				
	Customer Months	8,640	8,640	8,640
	On-Peak kWh	4,144,000	4,144,000	4,144,000
	Off-Peak kWh	7,696,000	7,696,000	7,696,000
S.C. No. 6 Alt TOU				
	Customer Months	8,160	8,160	8,160
	On-Peak kWh	1,198,500	1,198,500	1,198,500
	Off-Peak kWh	6,791,500	6,791,500	6,791,500
S.C. No. 9 - Traffic Signals				
	Signal Face Months	42,348	42,432	42,187
	kWh	720,000	720,000	720,000
S.C. No. 13 - Substation				
	Customer Months	60	48	48
	kWh	105,250,000	104,790,000	104,790,000
	kW	180,602	174,602	174,602
	Rkva	26,140	25,710	25,710
S.C. No. 13 - Transmission				
	Customer Months	72	72	72
	kWh	620,960,000	620,960,000	620,960,000
	kW	1,030,597	1,042,597	1,054,597
	Rkva	53,030	53,030	53,030

Appendix O Sheet 2 of 12

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Proposed Monthly Electric Base Delivery Rates
(Excludes S.C. Nos. 5 & 8, Unbilled & Interdepartmental)

		Current Rates	12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year
S.C. No. 1					
	Customer Charge	$ 21.50	$ 22.50	$ 24.00	$ 26.00
	kWh Delivery	$ 0.12777	$ 0.13860	$ 0.14554	$ 0.14920
S.C. No. 2 - Non-Demand					
	Customer Charge	$ 32.50	$ 33.50	$ 35.00	$ 37.00
	kWh Delivery	$ 0.10135	$ 0.11176	$ 0.11831	$ 0.12116
S.C. No. 2 - Secondary					
	Customer Charge	$ 140.00	$ 160.00	$ 180.00	$ 200.00
	HPP Customer Charge	$ 170.00	$ 193.00	$ 213.00	$ 233.00
	kWh Delivery	$ 0.00467	$ 0.00467	$ 0.00467	$ 0.00467
	kW Delivery	$ 14.78	$ 16.00	$ 16.55	$ 16.72
	Rkva*	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 2 - Primary					
	Customer Charge	$ 530.00	$ 570.00	$ 610.00	$ 650.00
	HPP Customer Charge	$ 560.00	$ 603.00	$ 643.00	$ 683.00
	kWh Delivery	$ 0.00144	$ 0.00144	$ 0.00144	$ 0.00144
	kW Delivery	$ 10.71	$ 11.70	$ 12.35	$ 12.73
	Rkva*	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 3					
	Customer Charge	$ 2,600.00	$ 2,750.00	$ 2,950.00	$ 3,200.00
	kWh Delivery	$ -	$ -	$ -	$ -
	kW Delivery	$ 13.56	$ 14.82	$ 15.60	$ 16.04
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 6					
	Customer Charge	$ 24.50	$ 25.50	$ 27.00	$ 29.00
	kWh Delivery On Pk	$ 0.16291	$ 0.17851	$ 0.18757	$ 0.19252
	kWh Delivery Off Pk	$ 0.05430	$ 0.05950	$ 0.06252	$ 0.06417
S.C. No. 6 (5 Hour On-Peak)					
	Customer Charge	$ 24.50	$ 25.50	$ 27.00	$ 29.00
	kWh Delivery On Pk	$ 0.13508	$ 0.14732	$ 0.15516	$ 0.15929
	kWh Delivery Off Pk	$ 0.11681	$ 0.12739	$ 0.13417	$ 0.13775
S.C. No. 9					
	Signal Faces	$ 4.97	$ 5.26	$ 5.52	$ 5.70
S.C. No. 13 - Substation					
	Customer Charge	$ 8,500.00	$ 9,700.00	$ 11,050.00	$ 12,500.00
	kWh Delivery	$ -	$ -	$ -	$ -
	kW Delivery	$ 10.96	$ 12.26	$ 12.74	$ 12.87
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 13 - Transmission					
	Customer Charge	$ 13,500.00	$ 15,500.00	$ 18,000.00	$ 21,000.00
	kWh Delivery	$ -	$ -	$ -	$ -
	kW Delivery	$ 6.57	$ 7.69	$ 8.04	$ 8.15
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83

Energy Efficiency Exemption Credit Rate per kW:					
	S.C. No. 2 - Secondary		$ 0.67	$ 0.75	$ 0.76
	S.C. No. 2 - Primary		$ 0.85	$ 0.94	$ 0.96
	S.C. No. 3		$ 0.93	$ 1.03	$ 1.05
	S.C. No. 13 - Substation		$ 1.14	$ 1.33	$ 1.36
	S.C. No. 13 - Transmission		$ 1.22	$ 1.33	$ 1.34

*As applicable

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Proposed Electric Merchant Function Charges

	Current Rates	12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year
MFC Administration Charge per kWh				
S.C. No. 1 - Residential	$ 0.00087	$ 0.00098	$ 0.00096	$ 0.00092
S.C. No. 2 - Non Demand	$ 0.00127	$ 0.00140	$ 0.00135	$ 0.00130
S.C. No. 2 - Primary Demand	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00006	$ 0.00007	$ 0.00007	$ 0.00007
S.C. No. 3 - Large Power Primary	$ -	$ -	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00226	$ 0.00279	$ 0.00283	$ 0.00286
S.C. No. 6 - Residential Time-of-Use	$ 0.00066	$ 0.00051	$ 0.00051	$ 0.00051
S.C. No. 8 - Street Lighting	$ 0.00015	$ 0.00016	$ 0.00016	$ 0.00016
S.C. No. 9 - Traffic Signals	$ 0.00062	$ 0.00069	$ 0.00069	$ 0.00069
S.C. No. 13 - Substation	$ -	$ -	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -	$ -	$ -
MFC Supply Charge per kWh				
S.C. No. 1 - Residential	$ 0.00206	$ 0.00326	$ 0.00316	$ 0.00304
S.C. No. 2 - Non Demand	$ 0.00302	$ 0.00462	$ 0.00448	$ 0.00431
S.C. No. 2 - Primary Demand	$ 0.00001	$ 0.00002	$ 0.00002	$ 0.00002
S.C. No. 2 - Secondary Demand	$ 0.00015	$ 0.00024	$ 0.00024	$ 0.00024
S.C. No. 3 - Large Power Primary	$ -	$ -	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00536	$ 0.00924	$ 0.00936	$ 0.00946
S.C. No. 6 - Residential Time-of-Use	$ 0.00155	$ 0.00170	$ 0.00170	$ 0.00170
S.C. No. 8 - Street Lighting	$ 0.00035	$ 0.00054	$ 0.00054	$ 0.00054
S.C. No. 9 - Traffic Signals	$ 0.00148	$ 0.00227	$ 0.00227	$ 0.00227
S.C. No. 13 - Substation	$ -	$ -	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -	$ -	$ -

Appendix O Sheet 4 of 12

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Proposed Electric Bill Credit

		12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year 3
S.C. No. 1 - Residential	per kWh	$ (0.00487)	$ (0.00438)	$ (0.00079)
S.C. No. 2 - Non Demand	per kWh	$ (0.00514)	$ (0.00458)	$ (0.00082)
S.C. No. 2 - Primary Demand	per kWh	$ (0.00097)	$ (0.00119)	$ (0.00024)
S.C. No. 2 - Secondary Demand	per kWh	$ (0.00219)	$ (0.00207)	$ (0.00039)
S.C. No. 3 - Large Power Primary	per kW	$ (0.45)	$ (0.55)	$ (0.11)
S.C. No. 5 - Area Lighting	per kWh	$ (0.00901)	$ (0.00667)	$ (0.00124)
S.C. No. 6 - Residential Time-of-Use	per kWh	$ (0.00346)	$ (0.00321)	$ (0.00059)
S.C. No. 8 - Street Lighting	per kWh	$ (0.01182)	$ (0.01349)	$ (0.00239)
S.C. No. 9 - Traffic Signals	per kWh	$ (0.00694)	$ (0.00694)	$ (0.00139)
S.C. No. 13 - Substation	per kW	$ (0.55)	$ (0.56)	$ (0.11)
S.C. No. 13 - Transmission	per kW	$ (0.37)	$ (0.42)	$ (0.09)

Central Hudson Gas & Electric Corporation
Electric Energy Efficiency Base Rate Design
Cases 24-E-0461 & 24-G-0462
Twelve Months Ending June 30, 2026

	Demand = 12.70%				Energy = 87.30%				
	Summer CP		Summer CP						Total
Energy Efficiency Allocation	kW	RNY kW	%	Allocation	RY MWh	RNY MWh	MWh %	Allocation	**Allocator**
SC 1 Residential	921,968		68.22%	8.66%	2,335,486		47.03%	41.05%	49.72%
SC 2 Non Demand	27,412		2.03%	0.26%	211,668		4.26%	3.72%	3.98%
SC 2 Secondary	278,953	2,088	20.49%	2.60%	1,332,903	13,237	26.57%	23.20%	25.80%
SC 2 Primary	28,260	716	2.04%	0.26%	222,628	2,248	4.44%	3.87%	4.13%
SC 3 Primary	42,416	1,212	3.05%	0.39%	321,512	6,191	6.35%	5.54%	5.93%
SC 5 Area Lighting	-		0.00%	0.00%	11,540		0.23%	0.20%	0.20%
SC 6 Residential TOU	3,432		0.25%	0.03%	11,840		0.24%	0.21%	0.24%
SC 8 Street Lighting	-		0.00%	0.00%	10,910		0.22%	0.19%	0.19%
SC 9 Traffic Signals	-		0.00%	0.00%	720		0.01%	0.01%	0.01%
SC 13 Substation	12,759	5,980	0.50%	0.06%	105,250	45,200	1.21%	1.06%	1.12%
SC 13 Transmission	66,181	20,000	3.42%	0.43%	620,960	152,143	9.44%	8.24%	8.68%
Total	1,381,381	29,996	100.00%	12.70%	5,185,417	219,020	100.00%	87.30%	100.00%

	Total	$ 11,117,000			**Non-RNY**	**Not**	**Non-RNY**	**Base Rates**	**Total**	**Recovery**				**Change**
	Allocator	**Allocation**	**All kW**	**RNY kW**	**kW**	**Collected**	**$/kW**	**$/kW**	**$/kW**	**All kW**	**RNY Credit**	**Total**	**Base Rate**	**From 23-E-0418**
SC 1 Residential	49.72%	$ 5,527,166										$ 5,527,166	$ 5,527,166	$ (1,088,888)
SC 2 Non Demand	3.98%	$ 442,266										$ 442,266	$ 442,266	$ (138,919)
SC 2 Secondary	25.80%	$ 2,868,098	4,284,328	25,056	4,259,272	$ 16,773	$ 0.004	$ 0.669	$ 0.673	$ 2,883,353	$ (16,863)	$ 2,866,490	$ 2,883,353	$ 356,803
SC 2 Primary	4.13%	$ 459,391	550,521	8,592	541,929	$ 7,170	$ 0.013	$ 0.834	$ 0.847	$ 466,291	$ (7,277)	$ 459,014	$ 466,291	$ 148,044
SC 3 Primary	5.93%	$ 659,227	724,280	14,544	709,736	$ 13,238	$ 0.019	$ 0.910	$ 0.929	$ 672,856	$ (13,511)	$ 659,345	$ 672,856	$ 256,082
SC 5 Area Lighting	0.20%	$ 22,516										$ 22,516	$ 22,516	$ (24,665)
SC 6 Residential TOU	0.24%	$ 26,684										$ 26,684	$ 26,684	$ (2,318)
SC 8 Street Lighting	0.19%	$ 21,351										$ 21,351	$ 21,351	$ (32,070)
SC 9 Traffic Signals	0.01%	$ 1,359										$ 1,359	$ 1,359	$ (944)
SC 13 Substation	1.12%	$ 124,423	180,602	71,760	108,842	$ 49,438	$ 0.454	$ 0.689	$ 1.143	$ 206,428	$ (82,022)	$ 124,406	$ 206,428	$ 92,908
SC 13 Transmission	8.68%	$ 964,409	1,030,597	240,000	790,597	$ 224,586	$ 0.284	$ 0.936	$ 1.220	$ 1,257,328	$ (292,800)	$ 964,528	$ 1,257,328	$ 635,458
Total	100.00%	$ 11,116,890									$ (412,473)	$ 11,115,125	$ 11,527,598	$ 201,491

Central Hudson Gas & Electric Corporation
Electric Energy Efficiency Base Rate Design
Cases 24-E-0461 & 24-G-0462
Twelve Months Ending June 30, 2027

	Demand = 12.70%				Energy = 87.30%				
Energy Efficiency Allocation	Summer CP kW	RNY kW	Summer CP %	Allocation	RY2 MWh	RNY MWh	MWh %	Allocation	**Total Allocator**
SC 1 Residential	921,968		68.22%	8.66%	2,405,419		47.59%	41.55%	50.21%
SC 2 Non Demand	27,412		2.03%	0.26%	218,579		4.33%	3.78%	4.03%
SC 2 Secondary	278,953	2,088	20.49%	2.60%	1,342,660	13,237	26.30%	22.96%	25.56%
SC 2 Primary	28,260	716	2.04%	0.26%	223,473	2,248	4.38%	3.82%	4.08%
SC 3 Primary	42,416	1,212	3.05%	0.39%	322,559	6,191	6.26%	5.46%	5.85%
SC 5 Area Lighting	-		0.00%	0.00%	11,400		0.23%	0.20%	0.20%
SC 6 Residential TOU	3,432		0.25%	0.03%	11,840		0.23%	0.20%	0.24%
SC 8 Street Lighting	-		0.00%	0.00%	10,900		0.22%	0.19%	0.19%
SC 9 Traffic Signals	-		0.00%	0.00%	720		0.01%	0.01%	0.01%
SC 13 Substation	12,759	5,980	0.50%	0.06%	104,790	45,200	1.18%	1.03%	1.09%
SC 13 Transmission	66,181	20,000	3.42%	0.43%	620,960	152,143	9.28%	8.10%	8.53%
Total	1,381,381	29,996	100.00%	12.70%	5,273,299	219,020	100.00%	87.30%	100.00%

	Total Allocator	$ 12,515,000 **Allocation**	**All kW**	**RNY kW**	**Non-RNY kW**	**Not Collected**	**Non-RNY $/kW**	**Base Rates $/kW**	**Total $/kW**	**Recovery** All kW	**Recovery** RNY Credit	**Recovery** Total	**Base Rate**	**Change From RY1**
SC 1 Residential	50.21%	$ 6,284,065										$ 6,284,065	$ 6,284,065	$ (176,573)
SC 2 Non Demand	4.03%	$ 504,765										$ 504,765	$ 504,765	$ (26,288)
SC 2 Secondary	25.56%	$ 3,199,381	4,315,346	25,056	4,290,290	$ 18,576	$ 0.004	$ 0.741	$ 0.745	$ 3,214,933	$ (18,667)	$ 3,196,266	$ 3,214,933	$ 85,640
SC 2 Primary	4.08%	$ 510,605	552,604	8,592	544,012	$ 7,939	$ 0.015	$ 0.924	$ 0.939	$ 518,895	$ (8,068)	$ 510,827	$ 518,895	$ 29,164
SC 3 Primary	5.85%	$ 732,294	726,674	14,544	712,130	$ 14,656	$ 0.021	$ 1.008	$ 1.029	$ 747,748	$ (14,966)	$ 732,782	$ 747,748	$ 39,277
SC 5 Area Lighting	0.20%	$ 24,692										$ 24,692	$ 24,692	$ (4,583)
SC 6 Residential TOU	0.24%	$ 29,603										$ 29,603	$ 29,603	$ (442)
SC 8 Street Lighting	0.19%	$ 23,599										$ 23,599	$ 23,599	$ (10,820)
SC 9 Traffic Signals	0.01%	$ 1,530										$ 1,530	$ 1,530	$ (314)
SC 13 Substation	1.09%	$ 136,792	174,602	71,760	102,842	$ 56,220	$ 0.547	$ 0.783	$ 1.330	$ 232,221	$ (95,441)	$ 136,780	$ 232,221	$ 17,135
SC 13 Transmission	8.53%	$ 1,067,768	1,042,597	240,000	802,597	$ 245,794	$ 0.306	$ 1.024	$ 1.330	$ 1,386,654	$ (319,200)	$ 1,067,454	$ 1,386,654	$ 90,911
Total	100.00%	$ 12,515,094									$ (456,342)	$ 12,512,363	$ 12,968,705	$ 43,107

Central Hudson Gas & Electric Corporation
Electric Energy Efficiency Base Rate Design
Cases 24-E-0461 & 24-G-0462
Twelve Months Ending June 30, 2028

	Demand = 12.70%				Energy = 87.30%				
Energy Efficiency Allocation	Summer CP kW	RNY kW	Summer CP %	Allocation	RY3 MWh	RNY MWh	MWh %	Allocation	**Total Allocator**
SC 1 Residential	921,968		68.22%	8.66%	2,504,347		48.42%	42.27%	50.94%
SC 2 Non Demand	27,412		2.03%	0.26%	226,930		4.39%	3.83%	4.09%
SC 2 Secondary	278,953	2,088	20.49%	2.60%	1,351,771	13,237	25.88%	22.59%	25.20%
SC 2 Primary	28,260	716	2.04%	0.26%	224,013	2,248	4.29%	3.74%	4.00%
SC 3 Primary	42,416	1,212	3.05%	0.39%	323,176	6,191	6.13%	5.35%	5.74%
SC 5 Area Lighting	-		0.00%	0.00%	11,280		0.22%	0.19%	0.19%
SC 6 Residential TOU	3,432		0.25%	0.03%	11,840		0.23%	0.20%	0.23%
SC 8 Street Lighting	-		0.00%	0.00%	10,900		0.21%	0.18%	0.18%
SC 9 Traffic Signals	-		0.00%	0.00%	720		0.01%	0.01%	0.01%
SC 13 Substation	12,759	5,980	0.50%	0.06%	104,790	45,200	1.15%	1.01%	1.07%
SC 13 Transmission	66,181	20,000	3.42%	0.43%	620,960	152,143	9.07%	7.91%	8.35%
Total	1,381,381	29,996	100.00%	12.70%	5,390,727	219,020	100.00%	87.30%	100.00%

	Total Allocator	$ 13,037,000 **Allocation**	**All kW**	**RNY kW**	**Non-RNY kW**	**Not Collected**	**Non-RNY $/kW**	**Base Rates $/kW**	**Total $/kW**	**Recovery** All kW	**Recovery** RNY Credit	**Recovery** Total	**Base Rate**	**Change From RY2**
SC 1 Residential	50.94%	$ 6,640,865										$ 6,640,865	$ 6,640,865	$ 993
SC 2 Non Demand	4.09%	$ 532,989										$ 532,989	$ 532,989	$ (5,796)
SC 2 Secondary	25.20%	$ 3,284,911	4,344,418	25,056	4,319,362	$ 18,945	$ 0.004	$ 0.756	$ 0.760	$ 3,301,758	$ (19,043)	$ 3,282,715	$ 3,301,758	$ (4,547)
SC 2 Primary	4.00%	$ 521,773	553,942	8,592	545,350	$ 8,093	$ 0.015	$ 0.942	$ 0.957	$ 530,122	$ (8,223)	$ 521,899	$ 530,122	$ 4,498
SC 3 Primary	5.74%	$ 748,042	728,089	14,544	713,545	$ 14,943	$ 0.021	$ 1.027	$ 1.048	$ 763,037	$ (15,242)	$ 747,795	$ 763,037	$ 5,064
SC 5 Area Lighting	0.19%	$ 24,811										$ 24,811	$ 24,811	$ (3,130)
SC 6 Residential TOU	0.23%	$ 30,269										$ 30,269	$ 30,269	$ (627)
SC 8 Street Lighting	0.18%	$ 24,015										$ 24,015	$ 24,015	$ (3,609)
SC 9 Traffic Signals	0.01%	$ 1,593										$ 1,593	$ 1,593	$ (85)
SC 13 Substation	1.07%	$ 139,424	174,602	71,760	102,842	$ 57,302	$ 0.557	$ 0.799	$ 1.356	$ 236,760	$ (97,307)	$ 139,453	$ 236,760	$ 1,449
SC 13 Transmission	8.35%	$ 1,088,290	1,054,597	240,000	814,597	$ 247,668	$ 0.304	$ 1.032	$ 1.336	$ 1,408,942	$ (320,640)	$ 1,088,302	$ 1,408,942	$ 10,248
Total	100.00%	$ 13,036,982									$ (460,455)	$ 13,034,706	$ 13,495,161	$ 4,456

Appendix O Sheet 8 of 12
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Standby Rates

Time Periods:
On-Peak Monday - Friday: 7am - 11pm, excluding holidays
Super-Peak Monday - Friday: June - September 2pm - 7pm, excluding holidays

Parent Service Classification		Current Rates	12 Months Ending 26-Jun Rate Year 1	12 Months Ending 27-Jun Rate Year 2	12 Months Ending 28-Jun Rate Year 3
S.C. No. 1					
Customer Charge		$ 21.50	$ 22.50	$ 24.00	$ 26.00
Contract Demand	per kW	$ 4.69	$ 4.93	$ 5.32	$ 5.64
Daily As-Used Demand On-Peak	per kW	$ 0.51714	$ 0.55433	$ 0.59722	$ 0.63781
Daily As-Used Demand Super-Peak		$ 0.20011	$ 0.21469	$ 0.23249	$ 0.24978
S.C. No. 2 - Non Demand					
Customer Charge		$ 32.50	$ 33.50	$ 35.00	$ 37.00
Contract Demand	per kW	$ 7.58	$ 8.43	$ 9.27	$ 9.86
Daily As-Used Demand On-Peak	per kW	$ 0.44750	$ 0.50446	$ 0.54221	$ 0.57480
Daily As-Used Demand Super-Peak	per kW	$ 0.20084	$ 0.22640	$ 0.24334	$ 0.25797
S.C. No. 2 - Secondary Demand					
Customer Charge		$ 140.00	$ 160.00	$ 180.00	$ 200.00
Contract Demand	per kW	$ 1.43	$ 1.44	$ 1.36	$ 1.22
Daily As-Used Demand On-Peak	per kW	$ 0.64351	$ 0.71147	$ 0.75183	$ 0.78041
Daily As-Used Demand Super-Peak	per kW	$ 0.21770	$ 0.24069	$ 0.25434	$ 0.26401
S.C. No. 2 - Primary Demand					
Customer Charge		$ 530.00	$ 570.00	$ 610.00	$ 650.00
Contract Demand	per kW	$ 3.03	$ 3.37	$ 3.53	$ 3.66
Daily As-Used Demand On-Peak	per kW	$ 0.42012	$ 0.44708	$ 0.47072	$ 0.49461
Daily As-Used Demand Super-Peak	per kW	$ 0.13268	$ 0.14120	$ 0.14866	$ 0.15621
S.C. No. 3					
Customer Charge		$ 2,600.00	$ 2,750.00	$ 2,950.00	$ 3,200.00
Contract Demand	per kW	$ 4.21	$ 4.63	$ 4.87	$ 4.96
Daily As-Used Demand On-Peak	per kW	$ 0.48852	$ 0.59914	$ 0.63436	$ 0.65732
Daily As-Used Demand Super-Peak	per kW	$ 0.15034	$ 0.18439	$ 0.19523	$ 0.20229
S.C. No. 6					
Customer Charge		$ 24.50	$ 25.50	$ 27.00	$ 29.00
Contract Demand	per kW	$ 4.12	$ 2.83	$ 2.97	$ 3.03
Daily As-Used Demand On-Peak	per kW	$ 0.51928	$ 0.39954	$ 0.42077	$ 0.43528
Daily As-Used Demand Super-Peak		$ 0.20161	$ 0.15375	$ 0.16192	$ 0.16751
S.C. No. 13 - Substation					
Customer Charge		$ 8,500.00	$ 9,700.00	$ 11,050.00	$ 12,500.00
Contract Demand	per kW	$ 3.09	$ 3.67	$ 3.87	$ 3.54
Daily As-Used Demand On-Peak	per kW	$ 0.37424	$ 0.41450	$ 0.40914	$ 0.42331
Daily As-Used Demand Super-Peak	per kW	$ 0.11882	$ 0.13160	$ 0.12990	$ 0.13440
S.C. No. 13 - Transmission					
Customer Charge		$ 13,500.00	$ 15,500.00	$ 18,000.00	$ 21,000.00
Contract Demand	per kW	$ 2.18	$ 2.65	$ 2.73	$ 2.70
Daily As-Used Demand On-Peak	per kW	$ 0.21296	$ 0.23858	$ 0.25615	$ 0.26780
Daily As-Used Demand Super-Peak	per kW	$ 0.07092	$ 0.07945	$ 0.08530	$ 0.08918

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Gas Billing Determinants

		12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year 3
S.C. No. 1 & 12 Res. Heat	Block 1 - Customer Months	821,157	811,586	799,543
	Block 1 - Mcf - Included in Customer Charge	159,411	157,210	156,278
	Block 2 - Mcf	2,237,009	2,200,227	2,137,847
	Block 3 - Mcf	3,002,828	3,015,177	3,050,833
		-	-	-
S.C. No. 1 & 12 Res. Non-Heat	Block 1 - Customer Months	99,877	111,711	125,665
	Block 1 - Mcf - Included in Customer Charge	17,619	19,393	21,242
	Block 2 - Mcf	101,157	105,479	110,574
	Block 3 - Mcf	50,143	47,702	45,152
S.C. No. 2, 6 & 13 Heat	Block 1 - Customer Months	133,836	132,062	130,490
	Block 1 - Mcf - Included in Customer Charge	28,988	28,630	28,635
	Block 2 - Mcf	850,572	840,307	833,455
	Block 3 - Mcf	3,947,435	3,900,200	3,866,498
	Block 4 - Mcf	1,097,950	1,083,295	1,069,819
S.C. No. 2, 6 & 13 Non-Heat	Block 1 - Customer Months	14,943	15,949	17,084
	Block 1 - Mcf - Included in Customer Charge	3,461	3,427	3,243
	Block 2 - Mcf	109,539	109,682	107,743
	Block 3 - Mcf	486,000	487,023	488,197
	Block 4 - Mcf	145,349	145,773	148,926
S.C. No. 6 High Volume		1,177,946	1,163,994	1,150,005
S.C. No. 11 Transmission	Block 1 - Customer Months	24	24	24
	Block 1 - Mcf - Included in Customer Charge	2,400	2,400	2,400
	Block 2 - Mcf	838,884	838,884	838,884
	MDQ	102,576	102,576	102,576
S.C. No. 11 Distribution	Block 1 - Customer Months	60	60	60
	Block 1 - Mcf - Included in Customer Charge	4,800	4,800	4,800
	Block 2 - Mcf	754,865	754,865	754,865
	MDQ	73,968	73,968	73,968
S.C. No. 11 - DLM	Block 1 - Customer Months	12	12	12
	Block 1 - Mcf - Included in Customer Charge	1,200	1,200	1,200
	Block 2 - Mcf	664,983	664,983	664,983
	MDQ	58,800	58,800	58,800
Interdepartmental (S.C. No. 2)	Block 4 - Mcf	22,680	22,680	22,680

Appendix O Sheet 10 of 12

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Proposed Monthly Gas Base Delivery Rates

			Current Rates	12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year 3
S.C. No. 1 & 12						
	Billing Block 1	First 2 Ccf	$ 26.25	$ 27.25	$ 28.75	$ 30.75
	Billing Block 2 per Ccf	Next 48 Ccf	$ 1.4915	$ 1.5467	$ 1.6768	$ 1.8318
	Billing Block 3 per Ccf	Additional	$ 1.2654	$ 1.5467	$ 1.6768	$ 1.8318
S.C. No. 2, 6 & 13						
	Billing Block 1	First 2 Ccf	$ 41.00	$ 43.00	$ 44.75	$ 46.25
	Billing Block 2 per Ccf	Next 98 Ccf	$ 0.6957	$ 0.7531	$ 0.8140	$ 0.8904
	Billing Block 3 per Ccf	Next 4900 Ccf	$ 0.6840	$ 0.7531	$ 0.8140	$ 0.8904
	Billing Block 4 per Ccf	Additional	$ 0.6452	$ 0.7531	$ 0.8140	$ 0.8904
S.C. No. 6 High Volume	Billing Block per Ccf	Additional	$ 0.5834	$ 0.7531	$ 0.8140	$ 0.8904
S.C. No. 11 Transmission	Customer Charge	First 1,000 Ccf	$ 4,000.00	$ 2,700.00	$ 2,700.00	$ 2,700.00
	Volumetric Charge per Ccf	Additional	$ 0.0231	$ 0.0280	$ 0.0315	$ 0.0265
	MDQ	Per Mcf of MDQ per Month	$ 11.06	$ 12.57	$ 13.33	$ 15.16
S.C. No. 11 Distribution	Customer Charge	First 1,000 Ccf	$ 2,400.00	$ 2,200.00	$ 2,200.00	$ 2,200.00
	Volumetric Charge per Ccf	Additional	$ 0.0500	$ 0.0600	$ 0.0650	$ 0.0600
	MDQ	Per Mcf of MDQ per Month	$ 26.01	$ 29.50	$ 31.70	$ 35.67
S.C. No. 11 DLM	Customer Charge	First 1,000 Ccf	$ 7,100.00	$ 5,600.00	$ 5,600.00	$ 5,600.00
	Volumetric Charge per Ccf	Additional	$ 0.0347	$ 0.0440	$ 0.0470	$ 0.0450
	MDQ	Per Mcf of MDQ per Month	$ 18.09	$ 20.62	$ 22.14	$ 24.83
S.C. No. 11 EG	Customer Charge		$ 3,000.00	$ 2,700.00	$ 2,700.00	$ 2,700.00
	MDQ	Per Mcf of MDQ per Month	$ 18.09	$ 20.38	$ 21.99	$ 23.94

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Gas Commodity Related Merchant Function Charges

		Current Rates	12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year 3
MFC Administration Charge per Ccf					
MFC-1	1 & 12	$ 0.00467	$ 0.00518	$ 0.00520	$ 0.00522
MFC-2	2, 6 & 13	$ 0.00465	$ 0.00516	$ 0.00523	$ 0.00528
MFC Supply Charge per Ccf					
MFC-1	1 & 12	$ 0.01239	$ 0.01248	$ 0.01253	$ 0.01258
MFC-2	2, 6 & 13	$ 0.01234	$ 0.01244	$ 0.01261	$ 0.01272

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Summary of Proposed Monthly Gas Bill Credit Rates

Applicable to S.C. No.		$/Ccf 12 Months Ending Jun-26 Rate Year 1		$/Ccf 12 Months Ending Jun-27 Rate Year 2		$/Ccf 12 Months Ending Jun-28 Rate Year 3	
1 & 12	$/Ccf	$	(0.04889)	$	(0.02716)	$	(0.02078)
2, 6 & 13	$/Ccf	$	(0.02092)	$	(0.01175)	$	(0.00897)
SC 11 Transmission	$/Ccf	$	(0.00369)	$	(0.00262)	$	(0.00196)
SC 11 Distribution	$/Ccf	$	(0.00889)	$	(0.00504)	$	(0.00383)
SC 11 - DLM	$/Ccf	$	(0.00574)	$	(0.00326)	$	(0.00248)

Gas bill credit rates reflect rate moderation as described in Section IV.D

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462

Electric Base Delivery Revenue Allocation- Rate Year 1

	Revenue Increase	Increase Percent
SC 1 Residential	$ 29,557,014	8.02%
SC 2 Non Demand	$ 2,762,846	7.87%
SC 2 Secondary	$ 7,616,565	8.57%
SC 2 Primary	$ 469,633	6.49%
SC 3 Primary	$ 723,616	6.52%
SC 5 Area Lighting	$ 255,475	9.35%
SC 6 Residential TOU	$ 115,680	8.87%
SC 8 Street Lighting	$ 380,213	6.49%
SC 9 Traffic Signals	$ 13,246	6.29%
SC 13 Substation	$ 214,232	8.69%
SC 13 Transmission	$ 664,001	8.69%
Total	$ 42,772,520	8.05%

*Results of revenue allocation presenting revenue increase/(decrease) utilized in base delivery rate design. Change in MFCs addressed separately through revised MFC rates and moderation addressed separately through bill credits.

Appendix P Sheet 2 of 6

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462

Electric Base Delivery Revenue Allocation- Rate Year 2

		Revenue Increase	Increase Percent
SC 1 Residential	$	21,701,291	5.33%
SC 2 Non Demand	$	2,088,738	5.42%
SC 2 Secondary	$	5,031,473	5.16%
SC 2 Primary	$	405,348	5.14%
SC 3 Primary	$	622,549	5.14%
SC 5 Area Lighting	$	157,973	5.32%
SC 6 Residential TOU	$	74,239	5.24%
SC 8 Street Lighting	$	318,642	5.15%
SC 9 Traffic Signals	$	11,294	5.06%
SC 13 Substation	$	130,825	5.14%
SC 13 Transmission	$	456,584	5.14%
Total	$	30,998,956	5.30%

*Results of revenue allocation presenting revenue increase/(decrease) utilized in base delivery rate design. Change in MFCs addressed separately through revised MFC rates and moderation addressed separately through bill credits.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462

Electric Base Delivery Revenue Allocation- Rate Year 3

	Revenue Increase	Increase Percent
SC 1 Residential	$ 15,650,377	3.53%
SC 2 Non Demand	$ 1,496,094	3.60%
SC 2 Secondary	$ 3,491,074	3.38%
SC 2 Primary	$ 280,267	3.37%
SC 3 Primary	$ 431,066	3.37%
SC 5 Area Lighting	$ 108,713	3.47%
SC 6 Residential TOU	$ 51,161	3.43%
SC 8 Street Lighting	$ 218,830	3.37%
SC 9 Traffic Signals	$ 7,670	3.28%
SC 13 Substation	$ 90,311	3.37%
SC 13 Transmission	$ 320,036	3.37%
Total	$ 22,145,600	3.50%

*Results of revenue allocation presenting revenue increase/(decrease) utilized in base delivery rate design. Change in MFCs addressed separately through revised MFC rates and moderation addressed separately through bill credits.

Appendix P Sheet 4 of 6

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462

Gas Base Delivery Revenue Allocation - Rate Year 1

Base Revenue Allocation (Excluding Incremental MFC)	Base Rev Increase	Interruptible Revenues	Danskammer Revenues	Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ 13,691,871	$ (1,690,536)	$ (603,763)	$ 109,997,234	60.20%	11.52%
SC 2, 6 & 13	$ 8,256,991	$ (1,019,491)	$ (364,104)	$ 66,310,819	36.20%	11.48%
SC 11 Transmission	$ 156,567	$ (24,412)	$ (8,718)	$ 1,547,718	0.69%	8.67%
SC 11 Distribution	$ 339,471	$ (41,914)	$ (14,969)	$ 2,728,054	1.50%	11.56%
SC 11 - DLM	$ 191,517	$ (23,647)	$ (8,445)	$ 1,539,067	0.85%	11.56%
SC 11 - EG (Excl Danskammer)	$ 129,584	$ -	$ -	$ 1,250,984	0.57%	11.56%
Total	$ 22,766,000	$ (2,800,000)	$ (1,000,000)	$ 183,373,876	100.00%	11.48%

Energy Efficiency Allocation	EE Allocation	Adj Base Rev Increase Incl EE	Interruptible & Danskammer Revenues	Adjusted Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ (565,942)	$ 13,092,511	$ (2,294,299)	$ 109,431,292	57.71%	10.95%
SC 2, 6 & 13	$ 447,845	$ 8,660,804	$ (1,383,595)	$ 66,758,664	38.17%	12.23%
SC 11 Transmission	$ 41,556	$ 198,123	$ (33,130)	$ 1,589,273	0.87%	11.58%
SC 11 Distribution	$ 39,025	$ 378,496	$ (56,884)	$ 2,767,080	1.67%	13.15%
SC 11 - DLM	$ 33,232	$ 224,749	$ (32,092)	$ 1,572,299	0.99%	13.96%
SC 11 - EG (Excl Danskammer)	$ 4,284	$ 133,868	$ -	$ 1,255,268	0.59%	11.94%
Total		$ 22,688,551	$ (3,800,000)	$ 183,373,876	100.00%	11.48%

* Results of revenue allocation presenting revenue increase/(decrease) utilized in base delivery rate design. Change in MFCs addressed separately through revised MFC rates and moderation addressed separately through bill credits.

Appendix P Sheet 5 of 6

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462

Gas Base Delivery Revenue Allocation - Rate Year 2

Base Revenue Allocation (Excluding Incremental MFC)	Base Rev Increase	Interruptible Revenues	Danskammer Revenues	Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ 10,596,940	$ (1,686,789)	$ (602,425)	$ 117,478,845	59.94%	7.61%
SC 2, 6 & 13	$ 6,418,118	$ (1,021,617)	$ (364,863)	$ 71,143,751	36.26%	7.59%
SC 11 Transmission	$ 154,242	$ (24,552)	$ (8,769)	$ 1,710,002	0.87%	7.61%
SC 11 Distribution	$ 268,575	$ (42,751)	$ (15,268)	$ 2,977,552	1.52%	7.61%
SC 11 - DLM	$ 152,609	$ (24,292)	$ (8,676)	$ 1,691,898	0.87%	7.61%
SC 11 - EG (Excl Danskammer)	$ 95,515	$ -	$ -	$ 1,350,715	0.54%	7.61%
Total	$ 17,686,000	$ (2,800,000)	$ (1,000,000)	$ 196,352,763	100.00%	7.60%

Energy Efficiency Allocation	EE Allocation	Adj Base Rev Increase Incl EE	Interruptible & Danskammer Revenues	Adjusted Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ 69,804	$ 10,662,863	$ (2,289,213)	$ 117,548,649	60.34%	7.67%
SC 2, 6 & 13	$ (36,939)	$ 6,370,617	$ (1,386,480)	$ 71,106,812	36.05%	7.54%
SC 11 Transmission	$ (13,825)	$ 140,417	$ (33,320)	$ 1,696,177	0.79%	6.74%
SC 11 Distribution	$ (9,914)	$ 258,661	$ (58,019)	$ 2,967,638	1.46%	7.25%
SC 11 - DLM	$ (10,342)	$ 142,267	$ (32,968)	$ 1,681,555	0.81%	6.95%
SC 11 - EG (Excl Danskammer)	$ 1,217	$ 96,732	$ -	$ 1,351,932	0.55%	7.71%
Total		$ 17,671,556	$ (3,800,000)	$ 196,352,763	100.00%	7.60%

* Results of revenue allocation presenting revenue increase/(decrease) utilized in base delivery rate design. Change in MFCs addressed separately through revised MFC rates and moderation addressed separately through bill credits.

Appendix P Sheet 6 of 6

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462

Gas Base Delivery Revenue Allocation - Rate Year 3

Base Revenue Allocation (Excluding Incremental MFC)	Base Rev Increase	Interruptible Revenues	Danskammer Revenues	Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ 12,428,584	$ (1,690,627)	$ (603,795)	$ 127,323,879	60.04%	8.64%
SC 2, 6 & 13	$ 7,482,579	$ (1,017,835)	$ (363,512)	$ 76,653,038	36.14%	8.64%
SC 11 Transmission	$ 179,904	$ (24,472)	$ (8,740)	$ 1,843,070	0.87%	8.65%
SC 11 Distribution	$ 314,704	$ (42,808)	$ (15,289)	$ 3,224,062	1.52%	8.65%
SC 11 - DLM	$ 178,335	$ (24,258)	$ (8,664)	$ 1,826,995	0.87%	8.65%
SC 11 - EG (Excl Danskammer)	$ 116,895	$ -	$ -	$ 1,468,695	0.56%	8.65%
Total	$ 20,701,000	$ (2,800,000)	$ (1,000,000)	$ 212,339,739	100.00%	8.64%

Energy Efficiency Allocation	EE Allocation	Adj Base Rev Increase Incl EE	Interruptible & Danskammer Revenues	Adjusted Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ 6,588	$ 12,431,279	$ (2,294,422)	$ 127,330,467	60.07%	8.65%
SC 2, 6 & 13	$ (4,539)	$ 7,473,904	$ (1,381,347)	$ 76,648,498	36.12%	8.64%
SC 11 Transmission	$ (924)	$ 178,980	$ (33,212)	$ 1,842,146	0.86%	8.59%
SC 11 Distribution	$ (592)	$ 314,112	$ (58,097)	$ 3,223,470	1.52%	8.63%
SC 11 - DLM	$ (675)	$ 177,660	$ (32,922)	$ 1,826,320	0.86%	8.61%
SC 11 - EG (Excl Danskammer)	$ 142	$ 117,037	$ -	$ 1,468,837	0.57%	8.66%
Total		$ 20,692,972	$ (3,800,000)	$ 212,339,739	100.00%	8.64%

* Results of revenue allocation presenting revenue increase/(decrease) utilized in base delivery rate design. Change in MFCs addressed separately through revised MFC rates and moderation addressed separately through bill credits.

Appendix Q Sheet 1 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Residential Typical Monthly Bill
Rate Year 1

ECAM (Energy Cost Adjustment Mechanism) rates based on a 12 month average

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Avg kWh	**630**	**630**	**540**	**540**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 21.50	$ 22.50	$ 21.50	$ 22.50	
Energy Delivery $/kWh					
Delivery Chrg	$0.12777	$0.13860	$0.12777	$0.13860	
System Benefits Chrg	$0.00866	$0.00866	$0.00866	$0.00866	
MFC Admin Chrg	$0.00087	$0.00098	$0.00087	$0.00098	
Transition Adj Chrg	$0.00036	$0.00036	$0.00036	$0.00036	
Electric Bill Credit	$0.00000	($0.00487)	$0.00000	($0.00487)	
Miscellaneous II	$0.00840	$0.00840	$0.00840	$0.00840	
Purchased Power Adjustment	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous Charges	$0.00529	$0.00529	$0.00529	$0.00529	
MFC Supply Chrg	$0.00249	$0.00326	$0.00249	$0.00326	
MPC	$0.08579	$0.08579	$0.08579	$0.08579	
MPA	($0.00222)	($0.00222)	($0.00222)	($0.00222)	
Rev Tax Factor:					
Weighted Rev Tax- Commodity	0.208%	0.208%	0.208%	0.208%	
Weighted Rev Tax- Delivery	2.258%	2.258%	2.258%	2.258%	
CHG&E Bill					
Basic Service Charge	$22.00	$23.02	$22.00	$23.02	
Energy Delivery					
Delivery	$82.35	$89.34	$70.59	$76.57	
MFC Admin Chrg	$0.56	$0.63	$0.48	$0.54	
Transition Adj Chrg	$0.23	$0.23	$0.20	$0.20	
EBC	$0.00	($3.14)	$0.00	($2.69)	
SBC	$5.58	$5.58	$4.78	$4.78	
Delivery Subtotal w/ Revenue Tax	$110.73	$115.66	$98.05	$102.43	
Energy Supply					
PPA	$0.00	$0.00	$0.00	$0.00	
MISC	$8.75	$8.75	$7.50	$7.50	
MPC	$54.16	$54.16	$46.42	$46.42	
MPA	($1.40)	($1.40)	($1.20)	($1.20)	
MFC Supply Chrg	$1.60	$2.10	$1.38	$1.80	
Energy Subtotal w/ Revenue Tax	$63.12	$63.61	$54.10	$54.52	
Low Income Bill Discount	$0.00	$0.00	$ (60.46)	$ (69.11)	(Tier 1 Discount)
Total Bill	**$173.84**	**$179.27**	**$91.69**	**$87.84**	

$ Total Delivery Increase		$5.43		($3.85)
% Total Delivery Increase		5.09%		-11.26%
$ Total Bill Increase		$5.43		($3.85)
% Total Bill Increase		3.12%		-4.20%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rate Year 1

Delivery Only				
Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
3	$ 22.40	$ 23.44	$ 1.04	4.7%
10	$ 23.34	$ 24.44	$ 1.09	4.7%
20	$ 24.69	$ 25.85	$ 1.16	4.7%
30	$ 26.03	$ 27.27	$ 1.23	4.7%
40	$ 27.38	$ 28.68	$ 1.30	4.8%
50	$ 28.72	$ 30.10	$ 1.37	4.8%
80	$ 32.76	$ 34.34	$ 1.58	4.8%
90	$ 34.10	$ 35.76	$ 1.65	4.8%
100	$ 35.45	$ 37.17	$ 1.72	4.9%
125	$ 38.81	$ 40.71	$ 1.90	4.9%
150	$ 42.18	$ 44.25	$ 2.07	4.9%
175	$ 45.54	$ 47.79	$ 2.25	4.9%
200	$ 48.90	$ 51.32	$ 2.42	5.0%
250	$ 55.63	$ 58.40	$ 2.77	5.0%
300	$ 62.35	$ 65.48	$ 3.12	5.0%
350	$ 69.08	$ 72.55	$ 3.47	5.0%
400	$ 75.81	$ 79.63	$ 3.82	5.0%
630	$ 106.75	$ 112.18	$ 5.43	5.1%
750	$ 122.89	$ 129.16	$ 6.27	5.1%
1,000	$ 156.52	$ 164.55	$ 8.02	5.1%
1,500	$ 223.79	$ 235.31	$ 11.52	5.1%
2,000	$ 291.05	$ 306.07	$ 15.02	5.2%
3,000	$ 425.58	$ 447.60	$ 22.02	5.2%
5,000	$ 694.63	$ 730.65	$ 36.01	5.2%
10,000	$ 1,367.27	$ 1,438.28	$ 71.00	5.2%

Total Bill				
Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
3	$ 22.72	$ 23.76	$ 1.04	4.6%
10	$ 24.41	$ 25.50	$ 1.09	4.5%
20	$ 26.82	$ 27.98	$ 1.16	4.3%
30	$ 29.23	$ 30.46	$ 1.23	4.2%
40	$ 31.64	$ 32.94	$ 1.30	4.1%
50	$ 34.05	$ 35.42	$ 1.37	4.0%
80	$ 41.28	$ 42.86	$ 1.58	3.8%
90	$ 43.69	$ 45.34	$ 1.65	3.8%
100	$ 46.10	$ 47.82	$ 1.72	3.7%
125	$ 52.12	$ 54.02	$ 1.90	3.6%
150	$ 58.15	$ 60.22	$ 2.07	3.6%
175	$ 64.18	$ 66.42	$ 2.25	3.5%
200	$ 70.20	$ 72.62	$ 2.42	3.5%
250	$ 82.25	$ 85.03	$ 2.77	3.4%
300	$ 94.30	$ 97.43	$ 3.12	3.3%
350	$ 106.36	$ 109.83	$ 3.47	3.3%
400	$ 118.41	$ 122.23	$ 3.82	3.2%
630	$ 173.84	$ 179.27	$ 5.43	3.1%
750	$ 202.77	$ 209.04	$ 6.27	3.1%
1,000	$ 263.02	$ 271.04	$ 8.02	3.0%
1,500	$ 383.53	$ 395.05	$ 11.52	3.0%
2,000	$ 504.05	$ 519.06	$ 15.02	3.0%
3,000	$ 745.07	$ 767.09	$ 22.02	3.0%
5,000	$ 1,227.12	$ 1,263.13	$ 36.01	2.9%
10,000	$ 2,432.24	$ 2,503.24	$ 71.00	2.9%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Appendix Q Sheet 3 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Residential Typical Monthly Bill
Rate Year 2

ECAM rates based on a 12 month average

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Avg kWh	**630**	**630**	**540**	**540**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 22.50	$ 24.00	$ 22.50	$ 24.00	
Energy Delivery $/kWh					
Delivery Chrg	$0.13860	$0.14554	$0.13860	$0.14554	
System Benefits Chrg	$0.00866	$0.00866	$0.00866	$0.00866	
MFC Admin Chrg	$0.00098	$0.00096	$0.00098	$0.00096	
Transition Adj Chrg	$0.00036	$0.00036	$0.00036	$0.00036	
Electric Bill Credit	($0.00487)	($0.00438)	($0.00487)	($0.00438)	
Miscellaneous II	$0.00840	$0.00840	$0.00840	$0.00840	
Purchased Power Adjustment	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous Charges	$0.00529	$0.00529	$0.00529	$0.00529	
MFC Supply Chrg	$0.00326	$0.00316	$0.00326	$0.00316	
MPC	$0.08579	$0.08579	$0.08579	$0.08579	
MPA	($0.00222)	($0.00222)	($0.00222)	($0.00222)	
Rev Tax Factor:					
Weighted Rev Tax- Commodity	0.208%	0.208%	0.208%	0.208%	
Weighted Rev Tax- Delivery	2.258%	2.258%	2.258%	2.258%	
CHG&E Bill					
Basic Service Charge	$23.02	$24.55	$23.02	$24.55	
Energy Delivery					
Delivery	$89.34	$93.81	$76.57	$80.41	
MFC Admin Chrg	$0.63	$0.62	$0.54	$0.53	
Transition Adj Chrg	$0.23	$0.23	$0.20	$0.20	
EBC	($3.14)	($2.82)	($2.69)	($2.42)	
SBC	$5.58	$5.58	$4.78	$4.78	
Delivery Subtotal w/ Revenue Tax	$115.66	$121.97	$102.43	$108.06	
Energy Supply					
PPA	$0.00	$0.00	$0.00	$0.00	
MISC	$8.75	$8.75	$7.50	$7.50	
MPC	$54.16	$54.16	$46.42	$46.42	
MPA	($1.40)	($1.40)	($1.20)	($1.20)	
MFC Supply Chrg	$2.10	$2.04	$1.80	$1.75	
Energy Subtotal w/ Revenue Tax	$63.61	$63.55	$54.52	$54.47	
Low Income Bill Discount	$0.00	$0.00	$ (69.11)	$ (69.11)	(Tier 1 Discount)
Total Bill	**$179.27**	**$185.52**	**$87.84**	**$93.42**	

$ Total Delivery Increase		$6.25		$5.57
% Total Delivery Increase		5.57%		18.37%
$ Total Bill Increase		$6.25		$5.57
% Total Bill Increase		3.48%		6.34%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Appendix Q Sheet 4 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Residential Typical Monthly Bill
Rate Year 2

Delivery Only				
Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
3	$ 23.44	$ 25.00	$ 1.56	6.6%
10	$ 24.44	$ 26.04	$ 1.61	6.6%
20	$ 25.85	$ 27.53	$ 1.68	6.5%
30	$ 27.27	$ 29.02	$ 1.76	6.5%
40	$ 28.68	$ 30.51	$ 1.83	6.4%
50	$ 30.10	$ 32.00	$ 1.91	6.3%
80	$ 34.34	$ 36.47	$ 2.13	6.2%
90	$ 35.76	$ 37.96	$ 2.21	6.2%
100	$ 37.17	$ 39.45	$ 2.28	6.1%
125	$ 40.71	$ 43.18	$ 2.47	6.1%
150	$ 44.25	$ 46.91	$ 2.66	6.0%
175	$ 47.79	$ 50.63	$ 2.84	6.0%
200	$ 51.32	$ 54.36	$ 3.03	5.9%
250	$ 58.40	$ 61.81	$ 3.40	5.8%
300	$ 65.48	$ 69.26	$ 3.78	5.8%
350	$ 72.55	$ 76.71	$ 4.15	5.7%
400	$ 79.63	$ 84.16	$ 4.53	5.7%
630	$ 112.18	$ 118.43	$ 6.25	5.6%
750	$ 129.16	$ 136.31	$ 7.14	5.5%
1,000	$ 164.55	$ 173.56	$ 9.01	5.5%
1,500	$ 235.31	$ 248.06	$ 12.75	5.4%
2,000	$ 306.07	$ 322.56	$ 16.49	5.4%
3,000	$ 447.60	$ 471.57	$ 23.97	5.4%
5,000	$ 730.65	$ 769.58	$ 38.93	5.3%
10,000	$ 1,438.28	$ 1,514.60	$ 76.32	5.3%

Total Bill				
Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
3	$ 23.76	$ 25.32	$ 1.56	6.6%
10	$ 25.50	$ 27.11	$ 1.61	6.3%
20	$ 27.98	$ 29.66	$ 1.68	6.0%
30	$ 30.46	$ 32.22	$ 1.76	5.8%
40	$ 32.94	$ 34.77	$ 1.83	5.6%
50	$ 35.42	$ 37.33	$ 1.91	5.4%
80	$ 42.86	$ 44.99	$ 2.13	5.0%
90	$ 45.34	$ 47.55	$ 2.21	4.9%
100	$ 47.82	$ 50.10	$ 2.28	4.8%
125	$ 54.02	$ 56.49	$ 2.47	4.6%
150	$ 60.22	$ 62.88	$ 2.66	4.4%
175	$ 66.42	$ 69.27	$ 2.84	4.3%
200	$ 72.62	$ 75.65	$ 3.03	4.2%
250	$ 85.03	$ 88.43	$ 3.40	4.0%
300	$ 97.43	$ 101.20	$ 3.78	3.9%
350	$ 109.83	$ 113.98	$ 4.15	3.8%
400	$ 122.23	$ 126.75	$ 4.53	3.7%
630	$ 179.27	$ 185.52	$ 6.25	3.5%
750	$ 209.04	$ 216.18	$ 7.14	3.4%
1,000	$ 271.04	$ 280.06	$ 9.01	3.3%
1,500	$ 395.05	$ 407.81	$ 12.75	3.2%
2,000	$ 519.06	$ 535.56	$ 16.49	3.2%
3,000	$ 767.09	$ 791.06	$ 23.97	3.1%
5,000	$ 1,263.13	$ 1,302.06	$ 38.93	3.1%
10,000	$ 2,503.24	$ 2,579.57	$ 76.32	3.0%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Appendix Q Sheet 5 of 23

Central Hudson Gas & Electric Corporation

Cases 24-E-0461 & 24-G-0462

Electric Residential Typical Monthly Bill

Rate Year 3

ECAM rates based on a 12 month average

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Avg kWh	**630**	**630**	**540**	**540**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 24.00	$ 26.00	$ 24.00	$ 26.00	
Energy Delivery $/kWh					
Delivery Chrg	$0.14554	$0.14920	$0.14554	$0.14920	
System Benefits Chrg	$0.00866	$0.00866	$0.00866	$0.00866	
MFC Admin Chrg	$0.00096	$0.00092	$0.00096	$0.00092	
Transition Adj Chrg	$0.00036	$0.00036	$0.00036	$0.00036	
Electric Bill Credit	($0.00438)	($0.00079)	($0.00438)	($0.00079)	
Miscellaneous II	$0.00840	$0.00840	$0.00840	$0.00840	
Purchased Power Adjustment	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous Charges	$0.00529	$0.00529	$0.00529	$0.00529	
MFC Supply Chrg	$0.00316	$0.00304	$0.00316	$0.00304	
MPC	$0.08579	$0.08579	$0.08579	$0.08579	
MPA	($0.00222)	($0.00222)	($0.00222)	($0.00222)	
Rev Tax Factor:					
Weighted Rev Tax- Commodity	0.208%	0.208%	0.208%	0.208%	
Weighted Rev Tax- Delivery	2.258%	2.258%	2.258%	2.258%	
CHG&E Bill					
Basic Service Charge	$24.55	$26.60	$24.55	$26.60	
Energy Delivery					
Delivery	$93.81	$96.17	$80.41	$82.43	
MFC Admin Chrg	$0.62	$0.59	$0.53	$0.51	
Transition Adj Chrg	$0.23	$0.23	$0.20	$0.20	
EBC	($2.82)	($0.51)	($2.42)	($0.44)	
SBC	$5.58	$5.58	$4.78	$4.78	
Delivery Subtotal w/ Revenue Tax	$121.97	$128.67	$108.06	$114.09	
Energy Supply					
PPA	$0.00	$0.00	$0.00	$0.00	
MISC	$8.75	$8.75	$7.50	$7.50	
MPC	$54.16	$54.16	$46.42	$46.42	
MPA	($1.40)	($1.40)	($1.20)	($1.20)	
MFC Supply Chrg	$2.04	$1.96	$1.75	$1.68	
Energy Subtotal w/ Revenue Tax	$63.55	$63.47	$54.47	$54.40	
Low Income Bill Discount	$0.00	$0.00	$ (69.11)	$ (69.11)	(Tier 1 Discount)
Total Bill	**$185.52**	**$192.14**	**$93.42**	**$99.38**	

$ Total Delivery Increase	$6.62	$5.96
% Total Delivery Increase	5.59%	16.61%
$ Total Bill Increase	$6.62	$5.96
% Total Bill Increase	3.57%	6.38%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Residential Typical Monthly Bill
Rate Year 3

Delivery Only

Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
3	$ 25.00	$ 27.07	$ 2.07	8.3%
10	$ 26.04	$ 28.16	$ 2.12	8.1%
20	$ 27.53	$ 29.73	$ 2.19	8.0%
30	$ 29.02	$ 31.29	$ 2.26	7.8%
40	$ 30.51	$ 32.85	$ 2.34	7.7%
50	$ 32.00	$ 34.41	$ 2.41	7.5%
80	$ 36.47	$ 39.10	$ 2.63	7.2%
90	$ 37.96	$ 40.66	$ 2.70	7.1%
100	$ 39.45	$ 42.23	$ 2.77	7.0%
125	$ 43.18	$ 46.13	$ 2.95	6.8%
150	$ 46.91	$ 50.04	$ 3.13	6.7%
175	$ 50.63	$ 53.95	$ 3.32	6.5%
200	$ 54.36	$ 57.85	$ 3.50	6.4%
250	$ 61.81	$ 65.67	$ 3.86	6.2%
300	$ 69.26	$ 73.48	$ 4.22	6.1%
350	$ 76.71	$ 81.29	$ 4.59	6.0%
400	$ 84.16	$ 89.10	$ 4.95	5.9%
630	$ 118.43	$ 125.04	$ 6.62	5.6%
750	$ 136.31	$ 143.79	$ 7.49	5.5%
1,000	$ 173.56	$ 182.86	$ 9.30	5.4%
1,500	$ 248.06	$ 260.99	$ 12.93	5.2%
2,000	$ 322.56	$ 339.12	$ 16.55	5.1%
3,000	$ 471.57	$ 495.38	$ 23.81	5.0%
5,000	$ 769.58	$ 807.89	$ 38.32	5.0%
10,000	$ 1,514.60	$ 1,589.18	$ 74.58	4.9%

Total Bill

Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
3	$ 25.32	$ 27.39	$ 2.07	8.2%
10	$ 27.11	$ 29.23	$ 2.12	7.8%
20	$ 29.66	$ 31.86	$ 2.19	7.4%
30	$ 32.22	$ 34.48	$ 2.26	7.0%
40	$ 34.77	$ 37.11	$ 2.34	6.7%
50	$ 37.33	$ 39.74	$ 2.41	6.5%
80	$ 44.99	$ 47.62	$ 2.63	5.8%
90	$ 47.55	$ 50.25	$ 2.70	5.7%
100	$ 50.10	$ 52.88	$ 2.77	5.5%
125	$ 56.49	$ 59.45	$ 2.95	5.2%
150	$ 62.88	$ 66.01	$ 3.13	5.0%
175	$ 69.27	$ 72.58	$ 3.32	4.8%
200	$ 75.65	$ 79.15	$ 3.50	4.6%
250	$ 88.43	$ 92.29	$ 3.86	4.4%
300	$ 101.20	$ 105.43	$ 4.22	4.2%
350	$ 113.98	$ 118.56	$ 4.59	4.0%
400	$ 126.75	$ 131.70	$ 4.95	3.9%
630	$ 185.52	$ 192.14	$ 6.62	3.6%
750	$ 216.18	$ 223.67	$ 7.49	3.5%
1,000	$ 280.06	$ 289.36	$ 9.30	3.3%
1,500	$ 407.81	$ 420.73	$ 12.93	3.2%
2,000	$ 535.56	$ 552.11	$ 16.55	3.1%
3,000	$ 791.06	$ 814.87	$ 23.81	3.0%
5,000	$ 1,302.06	$ 1,340.38	$ 38.32	2.9%
10,000	$ 2,579.57	$ 2,654.15	$ 74.58	2.9%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Appendix Q Sheet 7 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Bill Impacts

S.C. No. 2 - Non Demand

Rate Year 1

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	390	420	440	470	490	510	540	560	590
Present Bill	$ 118.58	$ 125.20	$ 129.61	$ 136.23	$ 140.64	$ 145.05	$ 151.67	$ 156.08	$ 162.69
Proposed Bill	$ 121.75	$ 128.53	$ 133.06	$ 139.84	$ 144.36	$ 148.88	$ 155.67	$ 160.19	$ 166.97
$ Increase	$ 3.17	$ 3.33	$ 3.44	$ 3.61	$ 3.72	$ 3.83	$ 4.00	$ 4.11	$ 4.28
% Increase	2.67%	2.66%	2.66%	2.65%	2.65%	2.64%	2.64%	2.63%	2.63%

Rate Year 2

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	390	420	440	470	490	510	540	560	590
Present Bill	$ 121.75	$ 128.53	$ 133.06	$ 139.84	$ 144.36	$ 148.88	$ 155.67	$ 160.19	$ 166.97
Proposed Bill	$ 125.96	$ 132.95	$ 137.61	$ 144.60	$ 149.26	$ 153.92	$ 160.91	$ 165.57	$ 172.57
$ Increase	$ 4.21	$ 4.42	$ 4.55	$ 4.76	$ 4.90	$ 5.04	$ 5.25	$ 5.39	$ 5.59
% Increase	3.46%	3.44%	3.42%	3.41%	3.39%	3.38%	3.37%	3.36%	3.35%

Rate Year 3

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	390	420	440	470	490	510	540	560	590
Present Bill	$ 125.96	$ 132.95	$ 137.61	$ 144.60	$ 149.26	$ 153.92	$ 160.91	$ 165.57	$ 172.57
Proposed Bill	$ 130.46	$ 137.64	$ 142.43	$ 149.62	$ 154.40	$ 159.19	$ 166.38	$ 171.16	$ 178.35
$ Increase	$ 4.50	$ 4.69	$ 4.82	$ 5.01	$ 5.14	$ 5.27	$ 5.46	$ 5.59	$ 5.78
% Increase	3.57%	3.53%	3.50%	3.47%	3.44%	3.42%	3.39%	3.38%	3.35%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 1

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 278.05	$ 303.08	$ 328.10	$ 428.20	$ 478.24					
Proposed Bill	$ 303.07	$ 327.53	$ 351.99	$ 449.82	$ 498.74					
$ Increase	$ 25.02	$ 24.46	$ 23.89	$ 21.62	$ 20.49					
Total % Increase	9.00%	8.07%	7.28%	5.05%	4.28%					
10										
Present Bill	$ 365.76	$ 390.79	$ 415.81	$ 515.91	$ 565.96					
Proposed Bill	$ 396.90	$ 421.36	$ 445.81	$ 543.65	$ 592.56					
$ Increase	$ 31.13	$ 30.57	$ 30.00	$ 27.74	$ 26.61					
% Increase	8.51%	7.82%	7.22%	5.38%	4.70%					
15										
Present Bill			$ 503.52	$ 603.62	$ 653.67	$ 903.91	$ 1,154.15			
Proposed Bill			$ 539.64	$ 637.47	$ 686.39	$ 930.96	$ 1,175.54			
$ Increase			$ 36.12	$ 33.85	$ 32.72	$ 27.06	$ 21.39			
% Increase			7.17%	5.61%	5.01%	2.99%	1.85%			
20										
Present Bill				$ 691.33	$ 741.38	$ 991.62	$ 1,241.86	$ 1,492.10		
Proposed Bill				$ 731.30	$ 780.21	$ 1,024.79	$ 1,269.37	$ 1,513.94		
$ Increase				$ 39.96	$ 38.83	$ 33.17	$ 27.51	$ 21.85		
% Increase				5.78%	5.24%	3.34%	2.22%	1.46%		
30										
Present Bill					$ 916.80	$ 1,167.04	$ 1,417.28	$ 1,667.52	$ 2,168.00	
Proposed Bill					$ 967.86	$ 1,212.44	$ 1,457.02	$ 1,701.59	$ 2,190.75	
$ Increase					$ 51.06	$ 45.39	$ 39.73	$ 34.07	$ 22.75	
% Increase					5.57%	3.89%	2.80%	2.04%	1.05%	
50										
Present Bill						$ 1,517.89	$ 1,768.13	$ 2,018.37	$ 2,518.85	$ 3,019.33
Proposed Bill						$ 1,587.74	$ 1,832.31	$ 2,076.89	$ 2,566.05	$ 3,055.20
$ Increase						$ 69.85	$ 64.18	$ 58.52	$ 47.20	$ 35.87
% Increase						4.60%	3.63%	2.90%	1.87%	1.19%
100										
Present Bill						$ 2,395.01	$ 2,645.25	$ 2,895.49	$ 3,395.97	$ 3,896.45
Proposed Bill						$ 2,525.99	$ 2,770.56	$ 3,015.14	$ 3,504.30	$ 3,993.45
$ Increase						$ 130.97	$ 125.31	$ 119.65	$ 108.33	$ 97.00
% Increase						5.47%	4.74%	4.13%	3.19%	2.49%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 2

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 303.07	$ 327.53	$ 351.99	$ 449.82	$ 498.74					
Proposed Bill	$ 325.93	$ 350.42	$ 374.91	$ 472.86	$ 521.83					
$ Increase	$ 22.86	$ 22.89	$ 22.92	$ 23.04	$ 23.10					
Total % Increase	7.54%	6.99%	6.51%	5.12%	4.63%					
10										
Present Bill	$ 396.90	$ 421.36	$ 445.81	$ 543.65	$ 592.56					
Proposed Bill	$ 422.51	$ 447.00	$ 471.49	$ 569.44	$ 618.41					
$ Increase	$ 25.61	$ 25.64	$ 25.67	$ 25.79	$ 25.85					
% Increase	6.45%	6.09%	5.76%	4.74%	4.36%					
15										
Present Bill			$ 539.64	$ 637.47	$ 686.39	$ 930.96	$ 1,175.54			
Proposed Bill			$ 568.07	$ 666.02	$ 715.00	$ 959.87	$ 1,204.75			
$ Increase			$ 28.43	$ 28.55	$ 28.61	$ 28.91	$ 29.21			
% Increase			5.27%	4.48%	4.17%	3.11%	2.48%			
20										
Present Bill				$ 731.30	$ 780.21	$ 1,024.79	$ 1,269.37	$ 1,513.94		
Proposed Bill				$ 762.60	$ 811.58	$ 1,056.45	$ 1,301.33	$ 1,546.21		
$ Increase				$ 31.31	$ 31.37	$ 31.67	$ 31.97	$ 32.27		
% Increase				4.28%	4.02%	3.09%	2.52%	2.13%		
30										
Present Bill					$ 967.86	$ 1,212.44	$ 1,457.02	$ 1,701.59	$ 2,190.75	
Proposed Bill					$ 1,004.74	$ 1,249.62	$ 1,494.49	$ 1,739.37	$ 2,229.13	
$ Increase					$ 36.88	$ 37.18	$ 37.48	$ 37.78	$ 38.38	
% Increase					3.81%	3.07%	2.57%	2.22%	1.75%	
50										
Present Bill						$ 1,587.74	$ 1,832.31	$ 2,076.89	$ 2,566.05	$ 3,055.20
Proposed Bill						$ 1,635.94	$ 1,880.82	$ 2,125.69	$ 2,615.45	$ 3,105.21
$ Increase						$ 48.20	$ 48.50	$ 48.80	$ 49.40	$ 50.00
% Increase						3.04%	2.65%	2.35%	1.93%	1.64%
100										
Present Bill						$ 2,525.99	$ 2,770.56	$ 3,015.14	$ 3,504.30	$ 3,993.45
Proposed Bill						$ 2,601.74	$ 2,846.62	$ 3,091.50	$ 3,581.26	$ 4,071.01
$ Increase						$ 75.76	$ 76.06	$ 76.36	$ 76.96	$ 77.56
% Increase						3.00%	2.75%	2.53%	2.20%	1.94%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 3

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 325.93	$ 350.42	$ 374.91	$ 472.86	$ 521.83					
Proposed Bill	$ 347.67	$ 372.58	$ 397.48	$ 497.12	$ 546.94					
$ Increase	$ 21.74	$ 22.16	$ 22.58	$ 24.26	$ 25.10					
Total % Increase	6.67%	6.32%	6.02%	5.13%	4.81%					
10										
Present Bill	$ 422.51	$ 447.00	$ 471.49	$ 569.44	$ 618.41					
Proposed Bill	$ 445.10	$ 470.01	$ 494.92	$ 594.55	$ 644.37					
$ Increase	$ 22.59	$ 23.01	$ 23.43	$ 25.11	$ 25.95					
% Increase	5.35%	5.15%	4.97%	4.41%	4.20%					
15										
Present Bill			$ 568.07	$ 666.02	$ 715.00	$ 959.87	$ 1,204.75			
Proposed Bill			$ 592.35	$ 691.98	$ 741.80	$ 990.89	$ 1,239.97			
$ Increase			$ 24.28	$ 25.96	$ 26.81	$ 31.01	$ 35.22			
% Increase			4.27%	3.90%	3.75%	3.23%	2.92%			
20										
Present Bill				$ 762.60	$ 811.58	$ 1,056.45	$ 1,301.33	$ 1,546.21		
Proposed Bill				$ 789.42	$ 839.23	$ 1,088.32	$ 1,337.41	$ 1,586.49		
$ Increase				$ 26.82	$ 27.66	$ 31.87	$ 36.08	$ 40.28		
% Increase				3.52%	3.41%	3.02%	2.77%	2.61%		
30										
Present Bill					$ 1,004.74	$ 1,249.62	$ 1,494.49	$ 1,739.37	$ 2,229.13	
Proposed Bill					$ 1,034.10	$ 1,283.19	$ 1,532.27	$ 1,781.36	$ 2,279.53	
Delivery Rate Increase					$ 29.36	$ 33.57	$ 37.78	$ 41.99	$ 50.40	
% Increase					2.92%	2.69%	2.53%	2.41%	2.26%	
50										
Present Bill						$ 1,635.94	$ 1,880.82	$ 2,125.69	$ 2,615.45	$ 3,105.21
Proposed Bill						$ 1,672.91	$ 1,922.00	$ 2,171.09	$ 2,669.26	$ 3,167.44
$ Increase						$ 36.98	$ 41.19	$ 45.39	$ 53.81	$ 62.23
% Increase						2.26%	2.19%	2.14%	2.06%	2.00%
100										
Present Bill						$ 2,601.74	$ 2,846.62	$ 3,091.50	$ 3,581.26	$ 4,071.01
Proposed Bill						$ 2,647.24	$ 2,896.33	$ 3,145.41	$ 3,643.59	$ 4,141.76
$ Increase						$ 45.49	$ 49.70	$ 53.91	$ 62.33	$ 70.75
% Increase						1.75%	1.75%	1.74%	1.74%	1.74%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Bill Impacts

S.C. No. 2 - Primary Demand

Rate Year 1

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 640.36	$ 665.00	$ 689.64	$ 788.19	$ 837.47					
Proposed Bill	$ 684.91	$ 709.30	$ 733.69	$ 831.25	$ 880.04					
$ Increase	$ 44.55	$ 44.30	$ 44.05	$ 43.06	$ 42.56					
Total % Increase	6.96%	6.66%	6.39%	5.46%	5.08%					
10										
Present Bill	$ 700.33	$ 724.97	$ 749.61	$ 848.17	$ 897.45					
Proposed Bill	$ 749.84	$ 774.23	$ 798.62	$ 896.19	$ 944.97					
$ Increase	$ 49.51	$ 49.26	$ 49.01	$ 48.02	$ 47.52					
Total % Increase	7.07%	6.79%	6.54%	5.66%	5.30%					
15										
Present Bill			$ 809.59	$ 908.14	$ 957.42	$ 1,203.81	$ 1,450.21			
Proposed Bill			$ 863.56	$ 961.13	$ 1,009.91	$ 1,253.82	$ 1,497.73			
$ Increase			$ 53.97	$ 52.98	$ 52.48	$ 50.00	$ 47.52			
Total % Increase			6.67%	5.83%	5.48%	4.15%	3.28%			
20										
Present Bill				$ 968.12	$ 1,017.40	$ 1,263.79	$ 1,510.18	$ 1,756.57		
Proposed Bill				$ 1,026.06	$ 1,074.84	$ 1,318.75	$ 1,562.67	$ 1,806.58		
$ Increase				$ 57.94	$ 57.44	$ 54.96	$ 52.48	$ 50.00		
Total % Increase				5.98%	5.65%	4.35%	3.48%	2.85%		
30										
Present Bill					$ 1,137.35	$ 1,383.74	$ 1,630.13	$ 1,876.53	$ 2,369.31	
Proposed Bill					$ 1,204.72	$ 1,448.63	$ 1,692.54	$ 1,936.45	$ 2,424.27	
$ Increase					$ 67.37	$ 64.88	$ 62.40	$ 59.92	$ 54.96	
Total % Increase					5.92%	4.69%	3.83%	3.19%	2.32%	
50										
Present Bill						$ 1,623.64	$ 1,870.04	$ 2,116.43	$ 2,609.21	$ 3,101.99
Proposed Bill						$ 1,708.37	$ 1,952.28	$ 2,196.19	$ 2,684.02	$ 3,171.84
$ Increase						$ 84.73	$ 82.25	$ 79.77	$ 74.81	$ 69.85
Total % Increase						5.22%	4.40%	3.77%	2.87%	2.25%
100										
Present Bill						$ 2,223.40	$ 2,469.79	$ 2,716.18	$ 3,208.97	$ 3,701.75
Proposed Bill						$ 2,357.73	$ 2,601.64	$ 2,845.55	$ 3,333.38	$ 3,821.20
$ Increase						$ 134.33	$ 131.85	$ 129.37	$ 124.41	$ 119.45
Total % Increase						6.04%	5.34%	4.76%	3.88%	3.23%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Appendix Q Sheet 12 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Bill Impacts

S.C. No. 2 - Primary Demand

Rate Year 2

kW		kWh 500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5	Present Bill	$ 684.91	$ 709.30	$ 733.69	$ 831.25	$ 880.04					
	Proposed Bill	$ 728.14	$ 752.47	$ 776.81	$ 874.15	$ 922.82					
	$ Increase	$ 43.23	$ 43.17	$ 43.12	$ 42.90	$ 42.79					
	Total % Increase	6.31%	6.09%	5.88%	5.16%	4.86%					
10	Present Bill	$ 749.84	$ 774.23	$ 798.62	$ 896.19	$ 944.97					
	Proposed Bill	$ 796.33	$ 820.67	$ 845.00	$ 942.35	$ 991.02					
	$ Increase	$ 46.49	$ 46.43	$ 46.38	$ 46.16	$ 46.05					
	Total % Increase	6.20%	6.00%	5.81%	5.15%	4.87%					
15	Present Bill			$ 863.56	$ 961.13	$ 1,009.91	$ 1,253.82	$ 1,497.73			
	Proposed Bill			$ 913.19	$ 1,010.54	$ 1,059.21	$ 1,302.57	$ 1,545.93			
	$ Increase			$ 49.63	$ 49.41	$ 49.30	$ 48.75	$ 48.20			
	Total % Increase			5.75%	5.14%	4.88%	3.89%	3.22%			
20	Present Bill				$ 1,026.06	$ 1,074.84	$ 1,318.75	$ 1,562.67	$ 1,806.58		
	Proposed Bill				$ 1,078.73	$ 1,127.40	$ 1,370.76	$ 1,614.12	$ 1,857.48		
	$ Increase				$ 52.67	$ 52.56	$ 52.01	$ 51.46	$ 50.91		
	Total % Increase				5.13%	4.89%	3.94%	3.29%	2.82%		
30	Present Bill					$ 1,204.72	$ 1,448.63	$ 1,692.54	$ 1,936.45	$ 2,424.27	
	Proposed Bill					$ 1,263.79	$ 1,507.15	$ 1,750.51	$ 1,993.87	$ 2,480.59	
	$ Increase					$ 59.07	$ 58.52	$ 57.97	$ 57.42	$ 56.32	
	Total % Increase					4.90%	4.04%	3.43%	2.97%	2.32%	
50	Present Bill						$ 1,708.37	$ 1,952.28	$ 2,196.19	$ 2,684.02	$ 3,171.84
	Proposed Bill						$ 1,779.92	$ 2,023.28	$ 2,266.64	$ 2,753.36	$ 3,240.08
	$ Increase						$ 71.55	$ 71.00	$ 70.45	$ 69.34	$ 68.24
	Total % Increase						4.19%	3.64%	3.21%	2.58%	2.15%
100	Present Bill						$ 2,357.73	$ 2,601.64	$ 2,845.55	$ 3,333.38	$ 3,821.20
	Proposed Bill						$ 2,461.85	$ 2,705.21	$ 2,948.57	$ 3,435.29	$ 3,922.01
	$ Increase						$ 104.12	$ 103.57	$ 103.01	$ 101.91	$ 100.81
	Total % Increase						4.42%	3.98%	3.62%	3.06%	2.64%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric Bill Impacts

S.C. No. 2 - Primary Demand

Rate Year 3

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 728.14	$ 752.47	$ 776.81	$ 874.15	$ 922.82					
Proposed Bill	$ 770.60	$ 795.17	$ 819.75	$ 918.04	$ 967.19					
$ Increase	$ 42.46	$ 42.70	$ 42.94	$ 43.89	$ 44.37					
Total % Increase	5.83%	5.67%	5.53%	5.02%	4.81%					
10										
Present Bill	$ 796.33	$ 820.67	$ 845.00	$ 942.35	$ 991.02					
Proposed Bill	$ 840.70	$ 865.27	$ 889.84	$ 988.14	$ 1,037.29					
$ Increase	$ 44.37	$ 44.61	$ 44.84	$ 45.80	$ 46.27					
Total % Increase	5.57%	5.44%	5.31%	4.86%	4.67%					
15										
Present Bill			$ 894.25	$ 991.60	$ 1,040.27	$ 1,283.63	$ 1,526.99			
Proposed Bill			$ 941.00	$ 1,039.30	$ 1,088.44	$ 1,334.18	$ 1,579.92			
$ Increase			$ 46.75	$ 47.70	$ 48.18	$ 50.56	$ 52.94			
Total % Increase			5.23%	4.81%	4.63%	3.94%	3.47%			
20										
Present Bill				$ 1,053.47	$ 1,102.15	$ 1,345.51	$ 1,588.87	$ 1,832.23		
Proposed Bill				$ 1,103.08	$ 1,152.23	$ 1,397.97	$ 1,643.71	$ 1,889.45		
$ Increase				$ 49.60	$ 50.08	$ 52.46	$ 54.84	$ 57.22		
Total % Increase				4.71%	4.54%	3.90%	3.45%	3.12%		
30										
Present Bill					$ 1,225.90	$ 1,469.26	$ 1,712.62	$ 1,955.99	$ 2,442.71	
Proposed Bill					$ 1,279.79	$ 1,525.53	$ 1,771.27	$ 2,017.01	$ 2,508.49	
$ Increase					$ 53.89	$ 56.27	$ 58.65	$ 61.03	$ 65.79	
Total % Increase					4.40%	3.83%	3.42%	3.12%	2.69%	
50										
Present Bill						$ 1,716.78	$ 1,960.14	$ 2,203.50	$ 2,690.22	$ 3,176.94
Proposed Bill						$ 1,780.66	$ 2,026.40	$ 2,272.14	$ 2,763.62	$ 3,255.10
$ Increase						$ 63.88	$ 66.26	$ 68.64	$ 73.40	$ 78.16
Total % Increase						3.72%	3.38%	3.12%	2.73%	2.46%
100										
Present Bill						$ 2,335.57	$ 2,578.93	$ 2,822.29	$ 3,309.01	$ 3,795.73
Proposed Bill						$ 2,418.49	$ 2,664.23	$ 2,909.97	$ 3,401.45	$ 3,892.93
$ Increase						$ 82.92	$ 85.30	$ 87.68	$ 92.44	$ 97.20
Total % Increase						3.55%	3.31%	3.11%	2.79%	2.56%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Appendix Q Sheet 14 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rates Utilized in Development of Typical Bills

		SC2ND		SC2SD		SC2PD
Market Price Charge	$	0.08579	$	0.08579	$	0.08531
Market Price Adjustment	$	(0.00222)	$	(0.00222)	$	0.00037
Miscellaneous Charges*	$	0.01959	$	0.00252	$	0.00252
Miscellaneous Charges (kW)*	$	-	$	2.72595	$	1.26018
Purchased Power Adjustment	$	-	$	-	$	-
System Benefits Charge- Current	$	0.00866	$	0.00866	$	0.00866
MFC Admin Charge- Current	$	0.00127	$	0.00006	$	0.00001
MFC Supply Charge- Current	$	0.00448	$	0.00032	$	0.00004
MFC Transition Adjustment-Current	$	0.00118	$	0.00009	$	0.00001
Electric Bill Credit- Current	$	-	$	-	$	-
Weighted Revenue Tax - Commodity		0.208%		0.208%		0.208%
Weighted Revenue Tax - Delivery		0.208%		0.208%		0.208%
MFC Admin Charge - Proposed RY1	$	0.00140	$	0.00007	$	0.00001
MFC Admin Charge - Proposed RY2	$	0.00135	$	0.00007	$	0.00001
MFC Admin Charge - Proposed RY3	$	0.00130	$	0.00007	$	0.00001
MFC Supply Charge - Proposed RY1	$	0.00462	$	0.00024	$	0.00002
MFC Supply Charge - Proposed RY2	$	0.00448	$	0.00024	$	0.00002
MFC Supply Charge - Proposed RY3	$	0.00431	$	0.00024	$	0.00002
Electric Bill Credit - Proposed RY1	$	(0.00514)	$	(0.00219)	$	(0.00097)
Electric Bill Credit - Proposed RY2	$	(0.00458)	$	(0.00207)	$	(0.00119)
Electric Bill Credit - Proposed RY3	$	(0.00082)	$	(0.00039)	$	(0.00024)
Customer Charge - Current	$	32.50	$	140.00	$	530.00
Customer Charge - Proposed RY1	$	33.50	$	160.00	$	570.00
Customer Charge - Proposed RY2	$	35.00	$	180.00	$	610.00
Customer Charge - Proposed RY3	$	37.00	$	200.00	$	650.00
Delivery Charge- Current	$	0.10135	$	0.00467	$	0.00144
Delivery Charge- Proposed RY1	$	0.11176	$	0.00467	$	0.00144
Delivery Charge- Proposed RY2	$	0.11831	$	0.00467	$	0.00144
Delivery Charge- Proposed RY3	$	0.12116	$	0.00467	$	0.00144
Demand Rate - Current		N/A	$	14.78	$	10.71
Demand Rate - Proposed RY1		N/A	$	16.00	$	11.70
Demand Rate - Proposed RY2		N/A	$	16.55	$	12.35
Demand Rate - Proposed RY3		N/A	$	16.72	$	12.73

*Miscellaneous Charges include EAM, DLM and RAM.

Appendix Q Sheet 15 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Average Annual Residential Gas Heating Customer Bill Impact
Rate Year 1 (Twelve Months Ended June 30, 2026)

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Block 1 Ccf	24	24	24	24	
Block 2 Ccf	417	417	398	398	
Block 3 Ccf	329	329	327	327	
Total Annual Ccf	**770**	**770**	**749**	**749**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 26.25	$ 27.25	$26.25	$27.25	
Gas Delivery Charges $/Ccf					
Next	$1.4915	$1.5467	$1.4915	$1.5467	
Next	$1.2654	$1.5467	$1.2654	$1.5467	
MISC	$0.04272	$0.04272	$0.04272	$0.04272	
MFC Admin Charge	$0.00467	$0.00518	$0.00467	$0.00518	
Transition Adj Charge	$0.00372	$0.00372	$0.00372	$0.00372	
Gas Bill Credit	$0.00000	($0.04889)	$0.00000	($0.04889)	
Gas Supply Charges $Ccf	$0.00000	$0.00000	$0.00000	$0.00000	
MFC Supply Charge	$0.01239	$0.01248	$0.01239	$0.01248	
Gas Supply Charge	$0.44852	$0.44852	$0.44852	$0.44852	
Rev Tax Factor					
Weighted Rev Tax - Commodity	0.00551	0.00551	0.00551	0.00551	
Weighted Rev Tax - Delivery	0.02551	0.02551	0.02551	0.02551	
CHG&E Bill			LOW INCOME		
Gas Delivery Charges:					
Basic Service Charge	$323.25	$335.56	$323.25	$335.56	
Next	$638.24	$661.86	$609.16	$631.70	
Next	$427.21	$522.19	$424.62	$519.01	
MISC	$33.76	$33.76	$32.83	$32.83	
MFC Admin Charge	$3.69	$4.09	$3.59	$3.98	
Transition Adj Charge	$2.94	$2.94	$2.86	$2.86	
Gas Bill Credit	$0.00	($38.63)	$0.00	($37.58)	
Subtotal Delivery	$1,429.08	$1,521.76	$1,396.30	$1,488.37	
Gas Supply Charges:					
MFC Supply Charge	$9.79	$9.86	$9.52	$9.59	
Gas Supply Charge	$347.27	$347.27	$337.80	$337.80	
Subtotal Energy Supply	$357.06	$357.14	$347.33	$347.39	
Low Income Bill Discount	$0.00	$0.00	($343.32)	($420.38)	(Tier 1 Discount)
Total Bill	**$1,786.15**	**$1,878.90**	**$1,400.31**	**$1,415.39**	
$ Total Delivery Increase		$92.75		$15.08	
% Total Delivery Increase		6.60%		1.46%	
$ Total Bill Increase		$92.75		$15.08	
% Total Bill Increase		5.19%		1.08%	

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Monthly Typical Bills
Residential

Rate Year 1 (Twelve Months Ended June 30, 2026)

Delivery Only				
Monthly Ccf	Bill at Current Rates	Bill at Proposed RY 1 Rates	Over Current Amount	Over Current %
2	$ 26.98	$ 27.91	$ 0.93	3.4%
4	$ 30.08	$ 31.02	$ 0.94	3.1%
6	$ 33.19	$ 34.14	$ 0.96	2.9%
8	$ 36.29	$ 37.26	$ 0.97	2.7%
10	$ 39.39	$ 40.38	$ 0.98	2.5%
15	$ 47.15	$ 48.17	$ 1.02	2.2%
20	$ 54.91	$ 55.97	$ 1.05	1.9%
25	$ 62.67	$ 63.76	$ 1.09	1.7%
30	$ 70.43	$ 71.56	$ 1.13	1.6%
35	$ 78.19	$ 79.35	$ 1.16	1.5%
40	$ 85.95	$ 87.15	$ 1.20	1.4%
50	$ 101.47	$ 102.74	$ 1.27	1.2%
60	$ 114.67	$ 118.33	$ 3.66	3.2%
80	$ 141.06	$ 149.51	$ 8.44	6.0%
100	$ 167.46	$ 180.68	$ 13.22	7.9%
110	$ 180.66	$ 196.27	$ 15.61	8.6%
130	$ 207.06	$ 227.45	$ 20.40	9.9%
150	$ 233.45	$ 258.63	$ 25.18	10.8%
170	$ 259.85	$ 289.81	$ 29.96	11.5%
200	$ 299.45	$ 336.58	$ 37.13	12.4%
300	$ 431.43	$ 492.48	$ 61.04	14.1%
400	$ 563.42	$ 648.37	$ 84.96	15.1%
500	$ 695.40	$ 804.27	$ 108.87	15.7%
600	$ 827.39	$ 960.16	$ 132.78	16.0%
800	$ 1,091.36	$ 1,271.96	$ 180.60	16.5%
1,000	$ 1,355.33	$ 1,583.75	$ 228.42	16.9%

Total Bill				
Monthly Ccf	Bill at Current Rates	Bill at Proposed RY 1 Rates	Over Current Amount	Over Current %
2	$ 27.97	$ 28.90	$ 0.93	3.3%
4	$ 32.06	$ 33.00	$ 0.94	2.9%
6	$ 36.16	$ 37.11	$ 0.96	2.6%
8	$ 40.25	$ 41.22	$ 0.97	2.4%
10	$ 44.34	$ 45.33	$ 0.98	2.2%
15	$ 54.58	$ 55.60	$ 1.02	1.9%
20	$ 64.81	$ 65.87	$ 1.05	1.6%
25	$ 75.04	$ 76.13	$ 1.09	1.5%
30	$ 85.28	$ 86.40	$ 1.13	1.3%
35	$ 95.51	$ 96.67	$ 1.16	1.2%
40	$ 105.74	$ 106.94	$ 1.20	1.1%
50	$ 126.21	$ 127.48	$ 1.27	1.0%
60	$ 144.36	$ 148.02	$ 3.66	2.5%
80	$ 180.65	$ 189.09	$ 8.44	4.7%
100	$ 216.95	$ 230.17	$ 13.22	6.1%
110	$ 235.09	$ 250.71	$ 15.61	6.6%
130	$ 271.39	$ 291.78	$ 20.40	7.5%
150	$ 307.68	$ 332.86	$ 25.18	8.2%
170	$ 343.97	$ 373.94	$ 29.96	8.7%
200	$ 398.42	$ 435.55	$ 37.13	9.3%
300	$ 579.88	$ 640.93	$ 61.04	10.5%
400	$ 761.35	$ 846.31	$ 84.96	11.2%
500	$ 942.82	$ 1,051.69	$ 108.87	11.5%
600	$ 1,124.29	$ 1,257.07	$ 132.78	11.8%
800	$ 1,487.23	$ 1,667.83	$ 180.60	12.1%
1,000	$ 1,850.17	$ 2,078.59	$ 228.42	12.3%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Commercial Gas Bills Impacts
Rate Year 1 (Twelve Months Ended June 30, 2026)

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Present Monthly Bill	Proposed RY 1 Monthly Bill	Delivery $ Increase	% Increase
2	42.24	44.21	1.97	4.66%
10	51.86	54.13	2.27	4.37%
30	75.93	78.95	3.01	3.97%
50	100.01	103.77	3.76	3.76%
100	160.18	165.81	5.63	3.51%
150	219.77	227.85	8.08	3.68%
200	279.36	289.90	10.53	3.77%
250	338.95	351.94	12.98	3.83%
300	398.54	413.98	15.44	3.87%
400	517.72	538.07	20.34	3.93%
500	636.90	662.15	25.25	3.96%
600	756.08	786.24	30.16	3.99%
800	994.44	1,034.41	39.97	4.02%
1000	1,232.80	1,282.58	49.78	4.04%
1500	1,828.70	1,903.01	74.31	4.06%
2000	2,424.60	2,523.44	98.84	4.08%
3000	3,616.39	3,764.30	147.90	4.09%
5000	5,999.99	6,246.01	246.02	4.10%
7500	8,881.94	9,348.15	466.21	5.25%
10000	11,763.90	12,450.29	686.40	5.83%
12000	14,069.46	14,932.01	862.55	6.13%
14000	16,375.02	17,413.72	1,038.70	6.34%
16000	18,680.59	19,895.44	1,214.85	6.50%
20000	23,291.72	24,858.87	1,567.15	6.73%
	Average Annual Heating Customer @ 6120 Ccf Per Year			
6120	7,787.23	8,096.24	309.02	3.97%

Weighted Revenue Tax Factor:		Delivery		0.00551
		Commodity		0.00551
**Gas Supply Charge (per Ccf):			$	0.44852
EAM (per Ccf):			$	0.00098
RAM (per Ccf):			$	0.01296
ARP (per Ccf):			$	0.00070
NPA (per Ccf):			$	0.00060

			Present		Proposed RY 1
*S.C. No. 2, 6 & 13 Base Delivery Rates					
Block 1	First 2 Ccf		41.00	$	43.00
Block 2 per Ccf	Next 98 Ccf	$	0.69570	$	0.75310
Block 3 per Ccf	Next 4900 Ccf	$	0.68400	$	0.75310
Block 4 per Ccf	Additional	$	0.64520	$	0.75310
*Merchant Function Charge (per Ccf):	MFC Admin	$	0.00465	$	0.00516
	MFC Supply	$	0.01234	$	0.01244
	Transition Adj.	$	0.02048	$	0.02048
*Delivery bill includes: Basic Service Charge, Delivery Ch		$	-	$	(0.02092)

In order to only show the impact of base rate increases, annual bills under proposed rates do not reflect changes to the ARP, EAM, RAM, NPA and GSC.
EAM, RAM, and ARP have been included at July 1, 2024 rates.
*Delivery Rates and MFC Charges in the present bill reflect rates effective August 1, 2024- June 30, 2025
** 12 month average

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Average Annual Residential Gas Heating Customer Bill Impact
Rate Year 2 (Twelve Months Ended June 30, 2027)

	Current RY1 Rates	Proposed RY2 Rates	Current RY1 Rates	Proposed RY2 Rates
Block 1 Ccf	24	24	24	24
Block 2 Ccf	417	417	398	398
Block 3 Ccf	329	329	327	327
Total Annual Ccf	**770**	**770**	**749**	**749**
			LOW INCOME	
CHG&E Rates				
Basic Service Charge	$ 27.25	$ 28.75	$27.25	$28.75
Gas Delivery Charges $/Ccf				
Next	$1.54670	$1.67680	$1.54670	$1.67680
Next	$1.54670	$1.67680	$1.54670	$1.67680
MISC	$0.04272	$0.04272	$0.04272	$0.04272
MFC Admin Charge	$0.00518	$0.00520	$0.00518	$0.00520
Transition Adj Charge	$0.00372	$0.00372	$0.00372	$0.00372
Gas Bill Credit	($0.04889)	($0.02716)	($0.04889)	($0.02716)
Gas Supply Charges $Ccf				
MFC Supply Charge	$0.01248	$0.01253	$0.01248	$0.01253
Gas Supply Charge	$0.44852	$0.44852	$0.44852	$0.44852
Rev Tax Factor				
Weighted Rev Tax - Commodity	0.00551	0.00551	0.00551	0.00551
Weighted Rev Tax - Delivery	0.02551	0.02551	0.02551	0.02551
CHG&E Bill			LOW INCOME	
Gas Delivery Charges:				
Basic Service Charge	$335.56	$354.03	$335.56	$354.03
Next	$661.86	$717.53	$631.70	$684.84
Next	$522.19	$566.11	$519.01	$562.67
MISC	$33.76	$33.76	$32.83	$32.83
MFC Admin Charge	$4.09	$4.11	$3.98	$4.00
Transition Adj Charge	$2.94	$2.94	$2.86	$2.86
Gas Bill Credit	($38.63)	($21.46)	($37.58)	($20.88)
Subtotal Delivery	$1,521.76	$1,657.01	$1,488.37	$1,620.35
Gas Supply Charges:				
MFC Supply Charge	$9.86	$9.90	$9.59	$9.63
Gas Supply Charge	$347.27	$347.27	$337.80	$337.80
Subtotal Energy Supply	$357.14	$357.17	$347.39	$347.43
Low Income Bill Discount	$0.00	$0.00	($420.38)	($420.38) (Tier 1 Discount)
Total Bill	**$1,878.90**	**$2,014.19**	**$1,415.39**	**$1,547.41**
$ Total Delivery Increase		$135.29		$132.02
% Total Delivery Increase		9.03%		12.64%
$ Total Bill Increase		$135.29		$132.02
% Total Bill Increase		7.20%		9.33%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Monthly Typical Bills

Residential

Rate Year 2 (Twelve Months Ended June 30, 2027)

Delivery Only				
Monthly Ccf	Bill at Current RY 1 Rates	Bill at Proposed RY 2 Rates	Over Current Amount	Over Current %
2	$ 27.91	$ 29.49	$ 1.58	5.7%
4	$ 31.02	$ 32.92	$ 1.90	6.1%
6	$ 34.14	$ 36.35	$ 2.21	6.5%
8	$ 37.26	$ 39.78	$ 2.52	6.8%
10	$ 40.38	$ 43.21	$ 2.83	7.0%
15	$ 48.17	$ 51.78	$ 3.61	7.5%
20	$ 55.97	$ 60.36	$ 4.39	7.8%
25	$ 63.76	$ 68.93	$ 5.17	8.1%
30	$ 71.56	$ 77.51	$ 5.95	8.3%
35	$ 79.35	$ 86.08	$ 6.73	8.5%
40	$ 87.15	$ 94.65	$ 7.51	8.6%
50	$ 102.74	$ 111.80	$ 9.07	8.8%
60	$ 118.33	$ 128.95	$ 10.62	9.0%
80	$ 149.51	$ 163.25	$ 13.74	9.2%
100	$ 180.68	$ 197.54	$ 16.86	9.3%
110	$ 196.27	$ 214.69	$ 18.42	9.4%
130	$ 227.45	$ 248.99	$ 21.54	9.5%
150	$ 258.63	$ 283.29	$ 24.65	9.5%
170	$ 289.81	$ 317.58	$ 27.77	9.6%
200	$ 336.58	$ 369.03	$ 32.45	9.6%
300	$ 492.48	$ 540.51	$ 48.04	9.8%
400	$ 648.37	$ 712.00	$ 63.62	9.8%
500	$ 804.27	$ 883.48	$ 79.21	9.8%
600	$ 960.16	$ 1,054.96	$ 94.80	9.9%
800	$ 1,271.96	$ 1,397.93	$ 125.97	9.9%
1,000	$ 1,583.75	$ 1,740.90	$ 157.15	9.9%

Total Bill				
Monthly Ccf	Bill at Current RY 1 Rates	Bill at Proposed RY 2 Rates	Over Current Amount	Over Current %
2	$ 28.90	$ 30.48	$ 1.58	5.5%
4	$ 33.00	$ 34.90	$ 1.90	5.7%
6	$ 37.11	$ 39.32	$ 2.21	5.9%
8	$ 41.22	$ 43.74	$ 2.52	6.1%
10	$ 45.33	$ 48.16	$ 2.83	6.2%
15	$ 55.60	$ 59.21	$ 3.61	6.5%
20	$ 65.87	$ 70.25	$ 4.39	6.7%
25	$ 76.13	$ 81.30	$ 5.17	6.8%
30	$ 86.40	$ 92.35	$ 5.95	6.9%
35	$ 96.67	$ 103.40	$ 6.73	7.0%
40	$ 106.94	$ 114.45	$ 7.51	7.0%
50	$ 127.48	$ 136.55	$ 9.07	7.1%
60	$ 148.02	$ 158.64	$ 10.62	7.2%
80	$ 189.09	$ 202.84	$ 13.74	7.3%
100	$ 230.17	$ 247.03	$ 16.86	7.3%
110	$ 250.71	$ 269.13	$ 18.42	7.3%
130	$ 291.78	$ 313.32	$ 21.54	7.4%
150	$ 332.86	$ 357.51	$ 24.65	7.4%
170	$ 373.94	$ 401.71	$ 27.77	7.4%
200	$ 435.55	$ 468.00	$ 32.45	7.4%
300	$ 640.93	$ 688.96	$ 48.04	7.5%
400	$ 846.31	$ 909.93	$ 63.62	7.5%
500	$ 1,051.69	$ 1,130.90	$ 79.21	7.5%
600	$ 1,257.07	$ 1,351.87	$ 94.80	7.5%
800	$ 1,667.83	$ 1,793.80	$ 125.97	7.6%
1,000	$ 2,078.59	$ 2,235.74	$ 157.15	7.6%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable

Appendix Q Sheet 20 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Commercial Gas Bills Impacts
Rate Year 2 (Twelve Months Ended June 30, 2027)

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Present RY 1 Monthly Bill	Proposed RY 2 Monthly Bill	Delivery $ Increase	% Increase
2	44.17	45.95	1.78	4.03%
10	53.96	56.31	2.34	4.34%
30	78.44	82.20	3.76	4.79%
50	102.92	108.10	5.17	5.03%
100	164.12	172.83	8.71	5.31%
150	225.32	237.57	12.24	5.43%
200	286.52	302.30	15.78	5.51%
250	347.72	367.04	19.31	5.55%
300	408.92	431.77	22.85	5.59%
400	531.33	561.24	29.92	5.63%
500	653.73	690.71	36.99	5.66%
600	776.13	820.18	44.06	5.68%
800	1,020.93	1,079.12	58.20	5.70%
1000	1,265.73	1,338.06	72.34	5.72%
1500	1,877.73	1,985.42	107.69	5.73%
2000	2,489.73	2,632.77	143.04	5.75%
3000	3,713.74	3,927.47	213.74	5.76%
5000	6,161.75	6,516.88	355.13	5.76%
7500	9,221.76	9,753.64	531.88	5.77%
10000	12,281.77	12,990.40	708.63	5.77%
12000	14,729.77	15,579.81	850.03	5.77%
14000	17,177.78	18,169.21	991.43	5.77%
16000	19,625.79	20,758.62	1,132.83	5.77%
20000	24,521.81	25,937.44	1,415.63	5.77%
	Average Annual Heating Customer @ 6120 Ccf Per Year			
6120	7,993.11	8,445.56	452.45	5.66%

Weighted Revenue Tax Factor:		Delivery				0.00551
		Commodity				0.00551
**Gas Supply Charge (per Ccf):					$	0.44852
EAM (per Ccf):					$	0.00098
RAM (per Ccf):					$	0.01296
ARP (per Ccf):					$	0.00070
NPA (per Ccf):					$	0.00060
			Present RY 1		Proposed RY 2	
*S.C. No. 2, 6 & 13 Base Delivery Rates						
Block 1	First 2 Ccf		43.00	$	44.75	
Block 2 per Ccf	Next 98 Ccf	$	0.75310	$	0.81400	
Block 3 per Ccf	Next 4900 Ccf	$	0.75310	$	0.81400	
Block 4 per Ccf	Additional	$	0.75310	$	0.81400	
*Merchant Function Charge (per Ccf):	MFC Admin	$	0.00516	$	0.00523	
	MFC Supply	$	0.01244	$	0.01261	
	Transition Adj.	$	0.00372	$	0.00372	
*Delivery bill includes: Basic Service Charge, Delivery Ch		$	(0.02092)	$	(0.01175)	

In order to only show the impact of base rate increases, annual bills under proposed rates do not reflect changes to the ARP, EAM, RAM, NPA and GSC.
EAM, RAM, and ARP have been included at July 1, 2024 rates.
*Delivery Rates and MFC Charges in the present bill reflect rates effective August 1, 2024- June 30, 2025
** 12 month average

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Appendix Q Sheet 21 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Average Annual Residential Gas Heating Customer Bill Impact
Rate Year 3 (Twelve Months Ended June 30, 2028)

	Current RY2 Rates	Proposed RY3 Rates	Current RY2 Rates	Proposed RY3 Rates	
Block 1 Ccf	24	24	24	24	
Block 2 Ccf	417	417	398	398	
Block 3 Ccf	329	329	327	327	
Total Annual Ccf	**770**	**770**	**749**	**749**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 28.75	$ 30.75	$28.75	$30.75	
Gas Delivery Charges $/Ccf					
Next	$1.67680	$1.83180	$1.67680	$1.83180	
Next	$1.67680	$1.83180	$1.67680	$1.83180	
MISC	$0.04272	$0.04272	$0.04272	$0.04272	
MFC Admin Charge	$0.00520	$0.00522	$0.00520	$0.00522	
Transition Adj Charge	$0.00372	$0.00372	$0.00372	$0.00372	
Gas Bill Credit	($0.02716)	($0.02078)	($0.02716)	($0.02078)	
Gas Supply Charges $Ccf					
MFC Supply Charge	$0.01253	$0.01258	$0.01253	$0.01258	
Gas Supply Charge	$0.44852	$0.44852	$0.44852	$0.44852	
Rev Tax Factor					
Weighted Rev Tax - Commodity	0.00551	0.00551	0.00551	0.00551	
Weighted Rev Tax - Delivery	0.02551	0.02551	0.02551	0.02551	
CHG&E Bill			LOW INCOME		
Gas Delivery Charges:					
Basic Service Charge	$354.03	$378.66	$354.03	$378.66	
Next	$717.53	$783.86	$684.84	$748.14	
Next	$566.11	$618.44	$562.67	$614.68	
MISC	$33.76	$33.76	$32.83	$32.83	
MFC Admin Charge	$4.11	$4.12	$4.00	$4.01	
Transition Adj Charge	$2.94	$2.94	$2.86	$2.86	
Gas Bill Credit	($21.46)	($16.42)	($20.88)	($15.97)	
Subtotal Delivery	$1,657.01	$1,805.36	$1,620.35	$1,765.21	
Gas Supply Charges:					
MFC Supply Charge	$9.90	$9.94	$9.63	$9.67	
Gas Supply Charge	$347.27	$347.27	$337.80	$337.80	
Subtotal Energy Supply	$357.17	$357.21	$347.43	$347.47	
Low Income Bill Discount	$0.00	$0.00	($420.38)	($420.38)	(Tier 1 Discount)
Total Bill	**$2,014.19**	**$2,162.57**	**$1,547.41**	**$1,692.31**	
$ Total Delivery Increase		$148.38		$144.90	
% Total Delivery Increase		9.09%		12.31%	
$ Total Bill Increase		$148.38		$144.90	
% Total Bill Increase		7.37%		9.36%	

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Appendix Q Sheet 22 of 23

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Monthly Typical Bills

Residential

Rate Year 3 (Twelve Months Ended June 30, 2028)

Delivery Only				
Monthly Ccf	Bill at Current RY 2 Rates	Bill at Proposed RY 3 Rates	Over Current Amount	Over Current %
2	$ 29.49	$ 31.56	$ 2.07	7.0%
4	$ 32.92	$ 35.32	$ 2.40	7.3%
6	$ 36.35	$ 39.08	$ 2.73	7.5%
8	$ 39.78	$ 42.84	$ 3.06	7.7%
10	$ 43.21	$ 46.60	$ 3.39	7.8%
15	$ 51.78	$ 56.00	$ 4.22	8.1%
20	$ 60.36	$ 65.41	$ 5.05	8.4%
25	$ 68.93	$ 74.81	$ 5.88	8.5%
30	$ 77.51	$ 84.21	$ 6.70	8.7%
35	$ 86.08	$ 93.61	$ 7.53	8.8%
40	$ 94.65	$ 103.02	$ 8.36	8.8%
50	$ 111.80	$ 121.82	$ 10.02	9.0%
60	$ 128.95	$ 140.63	$ 11.67	9.1%
80	$ 163.25	$ 178.24	$ 14.99	9.2%
100	$ 197.54	$ 215.85	$ 18.30	9.3%
110	$ 214.69	$ 234.65	$ 19.96	9.3%
130	$ 248.99	$ 272.26	$ 23.27	9.3%
150	$ 283.29	$ 309.87	$ 26.59	9.4%
170	$ 317.58	$ 347.48	$ 29.90	9.4%
200	$ 369.03	$ 403.90	$ 34.87	9.4%
300	$ 540.51	$ 591.95	$ 51.44	9.5%
400	$ 712.00	$ 780.00	$ 68.00	9.6%
500	$ 883.48	$ 968.05	$ 84.57	9.6%
600	$ 1,054.96	$ 1,156.10	$ 101.14	9.6%
800	$ 1,397.93	$ 1,532.20	$ 134.28	9.6%
1,000	$ 1,740.90	$ 1,908.31	$ 167.41	9.6%

Total Bill				
Monthly Ccf	Bill at Current RY 2 Rates	Bill at Proposed RY 3 Rates	Over Current Amount	Over Current %
2	$ 30.48	$ 32.55	$ 2.07	6.8%
4	$ 34.90	$ 37.30	$ 2.40	6.9%
6	$ 39.32	$ 42.05	$ 2.73	6.9%
8	$ 43.74	$ 46.80	$ 3.06	7.0%
10	$ 48.16	$ 51.55	$ 3.39	7.0%
15	$ 59.21	$ 63.43	$ 4.22	7.1%
20	$ 70.25	$ 75.30	$ 5.05	7.2%
25	$ 81.30	$ 87.18	$ 5.88	7.2%
30	$ 92.35	$ 99.06	$ 6.70	7.3%
35	$ 103.40	$ 110.93	$ 7.53	7.3%
40	$ 114.45	$ 122.81	$ 8.36	7.3%
50	$ 136.55	$ 146.56	$ 10.02	7.3%
60	$ 158.64	$ 170.32	$ 11.67	7.4%
80	$ 202.84	$ 217.82	$ 14.99	7.4%
100	$ 247.03	$ 265.33	$ 18.30	7.4%
110	$ 269.13	$ 289.08	$ 19.96	7.4%
130	$ 313.32	$ 336.59	$ 23.27	7.4%
150	$ 357.51	$ 384.10	$ 26.59	7.4%
170	$ 401.71	$ 431.61	$ 29.90	7.4%
200	$ 468.00	$ 502.87	$ 34.87	7.5%
300	$ 688.96	$ 740.40	$ 51.44	7.5%
400	$ 909.93	$ 977.94	$ 68.00	7.5%
500	$ 1,130.90	$ 1,215.47	$ 84.57	7.5%
600	$ 1,351.87	$ 1,453.01	$ 101.14	7.5%
800	$ 1,793.80	$ 1,928.08	$ 134.28	7.5%
1,000	$ 2,235.74	$ 2,403.15	$ 167.41	7.5%

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, Bill Credit (moderation), and Low Income Bill Discount, if applicable.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Commercial Gas Bills Impacts
Rate Year 3 (Twelve Months Ended June 30, 2028)

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Present RY 2 Monthly Bill	Proposed RY 3 Monthly Bill	Delivery $ Increase	% Increase
2	44.19	45.96	1.77	4.00%
10	54.55	56.95	2.40	4.41%
30	80.44	84.44	4.00	4.97%
50	106.34	111.93	5.60	5.26%
100	171.07	180.66	9.58	5.60%
150	235.81	249.38	13.57	5.76%
200	300.54	318.10	17.56	5.84%
250	365.28	386.83	21.55	5.90%
300	430.01	455.55	25.54	5.94%
400	559.48	593.00	33.52	5.99%
500	688.95	730.45	41.50	6.02%
600	818.42	867.90	49.47	6.05%
800	1,077.36	1,142.79	65.43	6.07%
1000	1,336.31	1,417.69	81.39	6.09%
1500	1,983.66	2,104.93	121.28	6.11%
2000	2,631.01	2,792.17	161.17	6.13%
3000	3,925.71	4,166.66	240.94	6.14%
5000	6,515.12	6,915.62	400.50	6.15%
7500	9,751.88	10,351.83	599.95	6.15%
10000	12,988.64	13,788.04	799.40	6.15%
12000	15,578.05	16,537.01	958.96	6.16%
14000	18,167.45	19,285.97	1,118.52	6.16%
16000	20,756.86	22,034.94	1,278.08	6.16%
20000	25,935.68	27,532.88	1,597.20	6.16%
	Average Annual Heating Customer @ 6120 Ccf Per Year			
6120	8,424.44	8,932.12	507.68	6.03%

Weighted Revenue Tax Factor:		Delivery			0.00551
		Commodity			0.00551
**Gas Supply Charge (per Ccf):				$	0.44852
EAM (per Ccf):				$	0.00098
RAM (per Ccf):				$	0.01296
ARP (per Ccf):				$	0.00070
NPA (per Ccf):				$	0.00060

			Present RY 2		Proposed RY 3
*S.C. No. 2, 6 & 13 Base Delivery Rates					
Block 1	First 2 Ccf		43.00	$	44.75
Block 2 per Ccf	Next 98 Ccf	$	0.81400	$	0.89040
Block 3 per Ccf	Next 4900 Ccf	$	0.81400	$	0.89040
Block 4 per Ccf	Additional	$	0.81400	$	0.89040
*Merchant Function Charge (per Ccf):	MFC Admin	$	0.00523	$	0.00528
	MFC Supply	$	0.01261	$	0.01272
	Transition Adj.	$	0.00372	$	0.00372
*Delivery bill includes: Basic Service Charge, Delivery Ch		$	(0.01175)	$	(0.00897)

In order to only show the impact of base rate increases, annual bills under proposed rates do not reflect changes to the ARP, EAM, RAM, NPA and GSC.
EAM, RAM, and ARP have been included at July 1, 2024 rates.
*Delivery Rates and MFC Charges in the present bill reflect rates effective August 1, 2024- June 30, 2025
** 12 month average

*Delivery bill includes: Basic Service Charge, Delivery Charge, MFC Admin Charge, MFC Supply Charge, Transition Adjustment, and Bill Credit (moderation), if applicable.

Appendix R Sheet 1 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric RDM Targets

		12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year 3
S.C. No. 1				
	Customer Months	3,256,138	3,256,611	3,257,313
	kWh	2,327,495,585	2,397,429,341	2,496,356,763
	Revenue	$ 394,388,063	$ 426,457,746	$ 465,059,980
S.C. No. 2 - Non-Demand				
	Customer Months	419,854	420,665	421,616
	kWh	211,668,053	218,578,796	226,930,488
	Revenue	$ 37,907,474	$ 40,856,488	$ 44,181,517
S.C. No. 2 - Secondary				
	Customer Months	137,489	137,995	138,338
	kWh	1,332,903,225	1,342,659,624	1,351,770,804
	kW	4,284,328	4,315,346	4,344,418
	Revenue	$ 94,361,164	$ 100,262,313	$ 106,602,762
S.C. No. 2 - Primary				
	Customer Months	1,820	1,832	1,803
	kWh	222,628,098	223,472,623	224,012,907
	kW	550,521	552,604	553,942
	Revenue	$ 7,640,202	$ 8,053,893	$ 8,548,324
S.C. No. 3				
	Customer Months	444	444	444
	kWh	321,512,000	322,558,548	323,175,706
	kW	724,280	726,674	728,089
	Revenue	$ 11,752,651	$ 12,373,684	$ 13,152,639
S.C. No. 5				
	Customer Months	45,756	45,114	45,114
	kWh	11,540,000	11,400,000	11,400,000
	Revenue	$ 2,997,563	$ 3,200,362	$ 3,372,033
S.C. No. 6				
	Customer Months	16,800	16,800	16,800
	kWh	19,830,000	19,830,000	19,830,000
	Revenue	$ 2,643,059	$ 2,789,436	$ 2,937,510
S.C. No. 8				
	Customer Months	2,544	2,544	2,544
	kWh	10,910,000	10,900,000	10,900,000
	Revenue	$ 6,092,590	$ 6,359,927	$ 6,681,617
S.C. No. 13 -Substation				
	Customer Months	60	48	48
	kWh	105,250,000	104,790,000	104,790,000
	kW	180,602	174,602	174,602
	Revenue	$ 2,718,538	$ 2,678,404	$ 2,798,876
S.C. No. 13- Transmission				
	Customer Months	72	72	72
	kWh	620,960,000	620,960,000	620,960,000
	kW	1,030,597	1,042,597	1,054,597
	Revenue	$ 8,704,007	$ 9,284,580	$ 9,882,515
RDM Revenue Target		**$ 569,205,311**	**$ 612,316,833**	**$ 663,217,773**

Note: Revenues are derived from customer charges, base rate energy delivery charges, base rate demand delivery charges and Merchant Function Charges

Appendix R Sheet 2 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric RDM Targets
Rate Year 1 (Twelve Months Ended June 30, 2026)

	July 2025	August 2025	September 2025	October 2025	November 2025	December 2025	January 2026	February 2026	March 2026	April 2026	May 2026	June 2026	Total
Service Classification No. 1													
Customer Months	279,936	268,613	276,839	276,958	273,352	261,558	276,837	265,325	269,323	268,759	271,592	267,046	3,256,138
MWh	212,386	210,618	187,518	159,112	169,414	191,686	246,330	239,009	211,620	182,682	159,336	157,784	2,327,496
Revenue	$ 35,601,547	$ 35,102,868	$ 32,100,689	$ 28,184,285	$ 29,524,622	$ 32,331,918	$ 40,215,053	$ 38,945,848	$ 35,257,069	$ 31,251,749	$ 28,094,404	$ 27,778,011	$ 394,388,063
Service Classification No. 2													
Nondemand													
Customer Months	34,136	34,978	33,704	36,672	35,210	34,142	36,381	34,084	35,789	34,460	35,740	34,558	419,854
MWh	15,828	16,763	14,940	15,357	17,117	19,024	22,170	21,212	20,699	17,907	15,872	14,779	211,668
Revenue	$ 2,926,452	$ 3,059,860	$ 2,812,007	$ 2,958,365	$ 3,107,578	$ 3,286,537	$ 3,715,977	$ 3,531,308	$ 3,530,428	$ 3,171,340	$ 2,985,177	$ 2,822,445	$ 37,907,474
Primary													
Customer Months	149	143	131	177	162	130	151	152	157	165	155	148	1,820
MWh	20,085	19,341	19,491	21,825	17,891	17,240	19,363	18,026	18,273	15,508	17,753	17,832	222,628
kW	52,848	48,363	47,539	57,434	43,626	42,052	44,005	45,068	41,529	40,811	46,719	40,527	550,521
Revenue	$ 719,639	$ 662,160	$ 646,165	$ 788,581	$ 614,886	$ 577,028	$ 613,659	$ 626,095	$ 587,366	$ 583,098	$ 648,641	$ 572,884	$ 7,640,202
Secondary													
Customer Months	11,945	11,555	11,107	12,261	11,153	11,057	11,720	11,035	11,636	11,392	11,506	11,122	137,489
MWh	131,836	132,843	120,698	107,348	99,188	104,354	114,697	107,899	104,624	97,068	102,729	109,619	1,332,903
kW	399,519	402,549	377,169	429,369	330,638	316,231	358,434	317,353	307,711	313,119	354,237	377,999	4,284,328
Revenue	$ 8,684,049	$ 8,670,694	$ 8,158,873	$ 9,139,849	$ 7,357,590	$ 7,124,137	$ 7,935,684	$ 7,149,851	$ 7,083,165	$ 7,110,662	$ 7,803,784	$ 8,142,826	$ 94,361,164
Service Classification No. 3													
Customer Months	37	37	37	37	37	37	37	37	37	37	37	37	444
MWh	31,211	30,108	22,133	32,199	26,643	23,119	26,252	25,326	23,345	27,206	26,499	27,471	321,512
kW	68,580	70,352	50,334	73,743	63,447	52,625	56,460	56,604	49,223	59,679	60,487	62,746	724,280
Revenue	$ 1,099,122	$ 1,124,995	$ 835,793	$ 1,173,979	$ 1,024,542	$ 866,992	$ 919,476	$ 922,751	$ 817,993	$ 969,687	$ 982,514	$ 1,014,807	$ 11,752,651
Service Classification No. 5													
Customer Months	3,840	3,840	3,840	3,840	3,840	3,840	3,786	3,786	3,786	3,786	3,786	3,786	45,756
MWh	760	840	930	1,080	1,160	1,280	1,200	1,000	970	860	770	690	11,540
Revenue	$ 249,742	$ 250,082	$ 250,331	$ 250,729	$ 251,018	$ 251,357	$ 249,938	$ 249,320	$ 249,240	$ 248,861	$ 248,622	$ 248,323	$ 2,997,563
Service Classification No. 6													
Customer Months	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	16,800
MWh	1,830	1,730	1,770	1,670	1,440	1,930	1,990	1,430	1,590	1,400	1,560	1,490	19,830
Revenue	$ 238,978	$ 232,204	$ 238,846	$ 224,172	$ 198,568	$ 251,882	$ 252,325	$ 192,322	$ 210,049	$ 190,786	$ 210,542	$ 202,385	$ 2,643,059
Service Classification No. 8													
Customer Months	212	212	212	212	212	212	212	212	212	212	212	212	2,544
MWh	710	790	870	1,010	1,090	1,200	1,150	950	930	820	740	650	10,910
Revenue	$ 511,188	$ 510,292	$ 509,407	$ 507,852	$ 506,956	$ 505,736	$ 503,787	$ 506,011	$ 506,227	$ 507,448	$ 508,343	$ 509,347	$ 6,092,590
Service Classification No. 13													
Substation													
Customer Months	6	6	6	6	6	6	4	4	4	4	4	4	60
MWh	9,530	9,570	8,800	8,860	8,480	8,260	9,120	7,630	8,840	8,530	8,720	8,910	105,250
kW	16,136	16,082	21,488	13,284	14,554	14,431	13,809	13,816	13,801	14,156	14,173	14,872	180,602
Revenue	$ 249,205	$ 248,565	$ 311,732	$ 215,794	$ 230,295	$ 229,193	$ 201,975	$ 201,981	$ 201,859	$ 206,374	$ 206,665	$ 214,900	$ 2,718,538
Service Classification No. 13													
Transmission													
Customer Months	6	6	6	6	6	6	6	6	6	6	6	6	72
MWh	58,910	57,260	53,180	52,080	49,700	48,810	48,880	45,340	50,040	50,580	52,460	53,720	620,960
kW	93,952	90,350	92,291	90,541	80,569	81,737	77,281	77,708	86,108	83,988	85,776	90,296	1,030,597
Revenue	$ 784,208	$ 757,970	$ 772,182	$ 760,730	$ 686,829	$ 695,207	$ 661,226	$ 664,388	$ 728,440	$ 711,164	$ 724,243	$ 757,420	$ 8,704,007
Total RDM Revenue Target	**$ 51,064,130**	**$ 50,619,690**	**$ 46,636,025**	**$ 44,204,336**	**$ 43,502,884**	**$ 46,119,987**	**$ 55,269,100**	**$ 52,989,875**	**$ 49,171,836**	**$ 44,951,169**	**$ 42,412,935**	**$ 42,263,348**	**$ 569,205,311**

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric RDM Targets
Rate Year 2 (Twelve Months Ended June 30, 2027)

	July 2026	August 2026	September 2026	October 2026	November 2026	December 2026	January 2027	February 2027	March 2027	April 2027	May 2027	June 2027	Total
Service Classification No. 1													
Customer Months	280,258	268,473	277,026	277,335	273,073	261,762	276,897	264,988	269,391	268,985	271,681	266,742	3,256,611
MWh	198,570	211,138	188,810	162,419	176,029	201,934	261,712	254,515	224,949	193,025	164,593	159,735	2,397,429
Revenue	$ 35,574,432	$ 37,117,555	$ 34,078,980	$ 30,252,316	$ 32,127,292	$ 35,619,418	$ 44,667,011	$ 43,335,627	$ 39,146,133	$ 34,498,330	$ 30,432,451	$ 29,608,201	$ 426,457,746
Service Classification No. 2													
Nondemand													
Customer Months	34,694	34,549	33,473	36,842	35,367	34,239	36,553	34,012	35,914	34,376	35,956	34,690	420,665
MWh	16,062	16,585	14,917	15,717	17,879	19,911	23,439	22,349	21,708	18,629	16,369	15,013	218,579
Revenue	$ 3,134,734	$ 3,192,089	$ 2,955,031	$ 3,168,695	$ 3,375,433	$ 3,578,857	$ 4,081,759	$ 3,862,403	$ 3,852,278	$ 3,430,440	$ 3,215,541	$ 3,009,228	$ 40,856,488
Primary													
Customer Months	151	151	146	176	163	139	147	150	150	163	153	143	1,832
MWh	20,183	19,545	19,547	21,840	17,951	17,403	19,509	18,066	18,334	15,566	17,729	17,800	223,473
kW	53,113	48,863	47,676	57,474	43,782	42,449	44,338	45,168	41,671	40,960	46,655	40,455	552,604
Revenue	$ 760,100	$ 706,050	$ 688,607	$ 827,869	$ 648,126	$ 616,058	$ 645,713	$ 657,469	$ 614,050	$ 613,405	$ 679,240	$ 597,206	$ 8,053,893
Secondary													
Customer Months	11,990	11,597	11,148	12,309	11,200	11,095	11,766	11,079	11,677	11,429	11,543	11,162	137,995
MWh	132,730	134,057	121,512	108,070	99,867	105,413	115,970	108,719	105,396	97,746	103,061	110,119	1,342,660
kW	402,208	406,232	379,730	432,279	332,895	319,427	362,410	319,765	309,982	315,310	355,384	379,724	4,315,346
Revenue	$ 9,214,103	$ 9,212,746	$ 8,657,164	$ 9,693,270	$ 7,822,068	$ 7,595,870	$ 8,458,206	$ 7,608,175	$ 7,543,664	$ 7,567,041	$ 8,267,569	$ 8,622,437	$ 100,262,313
Service Classification No. 3													
Customer Months	37	37	37	37	37	37	37	37	37	37	37	37	444
MWh	31,339	30,340	22,202	32,262	26,723	23,286	26,421	25,384	23,409	27,269	26,471	27,451	322,559
kW	68,864	70,905	50,494	73,889	63,641	53,014	56,829	56,737	49,361	59,820	60,420	62,700	726,674
Revenue	$ 1,157,808	$ 1,188,885	$ 880,101	$ 1,234,064	$ 1,078,380	$ 916,375	$ 971,097	$ 970,918	$ 861,224	$ 1,020,062	$ 1,030,322	$ 1,064,448	$ 12,373,684
Service Classification No. 5													
Customer Months	3,786	3,786	3,786	3,786	3,786	3,786	3,733	3,733	3,733	3,733	3,733	3,733	45,114
MWh	750	830	920	1,060	1,150	1,260	1,190	990	960	850	760	680	11,400
Revenue	$ 265,857	$ 266,384	$ 266,844	$ 267,660	$ 268,069	$ 268,756	$ 267,683	$ 266,607	$ 266,447	$ 265,820	$ 265,361	$ 264,874	$ 3,200,362
Service Classification No. 6													
Customer Months	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	16,800
MWh	1,830	1,730	1,770	1,670	1,440	1,930	1,990	1,430	1,590	1,400	1,560	1,490	19,830
Revenue	$ 252,216	$ 245,087	$ 252,108	$ 236,599	$ 209,578	$ 265,825	$ 266,242	$ 202,970	$ 221,646	$ 201,346	$ 222,212	$ 213,607	$ 2,789,436
Service Classification No. 8													
Customer Months	212	212	212	212	212	212	212	212	212	212	212	212	2,544
MWh	710	790	870	1,010	1,090	1,200	1,140	950	930	820	740	650	10,900
Revenue	$ 533,073	$ 532,044	$ 531,025	$ 529,236	$ 528,207	$ 526,803	$ 526,492	$ 528,925	$ 529,175	$ 530,579	$ 531,608	$ 532,762	$ 6,359,927
Service Classification No. 13													
Substation													
Customer Months	4	4	4	4	4	4	4	4	4	4	4	4	48
MWh	9,460	9,500	8,730	8,800	8,410	8,140	9,120	7,630	8,840	8,530	8,720	8,910	104,790
kW	15,136	15,082	20,488	12,284	13,554	13,431	13,809	13,816	13,801	14,156	14,173	14,872	174,602
Revenue	$ 230,534	$ 229,854	$ 295,587	$ 195,811	$ 210,890	$ 209,789	$ 213,857	$ 213,883	$ 213,741	$ 218,433	$ 218,733	$ 227,292	$ 2,678,404
Service Classification No. 13													
Transmission													
Customer Months	6	6	6	6	6	6	6	6	6	6	6	6	72
MWh	58,910	57,260	53,180	52,080	49,700	48,810	48,880	45,340	50,040	50,580	52,460	53,720	620,960
kW	94,952	91,350	93,291	91,541	81,569	82,737	78,281	78,708	87,108	84,988	86,776	91,296	1,042,597
Revenue	$ 835,000	$ 807,683	$ 822,478	$ 810,503	$ 733,621	$ 742,340	$ 707,032	$ 710,323	$ 776,895	$ 758,985	$ 772,584	$ 807,136	$ 9,284,580
Total RDM Revenue Target	**$ 51,957,857**	**$ 53,498,377**	**$ 49,427,925**	**$ 47,216,023**	**$ 47,001,664**	**$ 50,340,091**	**$ 60,805,092**	**$ 58,357,300**	**$ 54,025,253**	**$ 49,104,441**	**$ 45,635,621**	**$ 44,947,191**	**$ 612,316,833**

Appendix R Sheet 4 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric RDM Targets
Rate Year 3 (Twelve Months Ended June 30, 2028)

	July 2027	August 2027	September 2027	October 2027	November 2027	December 2027	January 2028	February 2028	March 2028	April 2028	May 2028	June 2028	Total
Service Classification No. 1													
Customer Months	280,356	268,510	276,849	277,310	273,452	261,599	276,953	265,311	269,307	268,985	272,082	266,599	3,257,313
MWh	198,596	211,096	189,930	165,759	184,496	214,181	279,384	273,405	240,726	205,104	171,492	162,187	2,496,357
Revenue	$ 37,549,239	$ 39,145,814	$ 36,137,606	$ 32,466,830	$ 35,221,508	$ 39,436,397	$ 49,770,437	$ 48,556,890	$ 43,681,516	$ 38,245,278	$ 33,204,362	$ 31,644,103	$ 465,059,980
Service Classification No. 2													
Nondemand													
Customer Months	34,595	34,818	33,658	36,885	35,430	34,300	36,598	34,136	35,968	34,508	35,984	34,736	421,616
MWh	16,080	16,765	15,105	16,037	18,532	20,961	24,880	23,862	22,990	19,600	16,887	15,230	226,930
Revenue	$ 3,305,404	$ 3,399,873	$ 3,147,853	$ 3,384,530	$ 3,644,904	$ 3,909,082	$ 4,487,768	$ 4,268,463	$ 4,226,358	$ 3,745,488	$ 3,458,303	$ 3,203,491	$ 44,181,517
Primary													
Customer Months	150	144	132	177	162	131	147	150	150	163	154	143	1,803
MWh	20,209	19,635	19,602	21,843	17,994	17,481	19,536	18,135	18,395	15,619	17,778	17,784	224,013
kW	53,184	49,091	47,810	57,484	43,888	42,637	44,402	45,339	41,807	41,102	46,782	40,416	553,942
Revenue	$ 805,765	$ 747,682	$ 723,811	$ 878,263	$ 689,086	$ 651,579	$ 687,829	$ 700,066	$ 655,113	$ 652,159	$ 722,271	$ 634,700	$ 8,548,324
Secondary													
Customer Months	12,021	11,638	11,189	12,339	11,225	11,131	11,790	11,106	11,699	11,458	11,563	11,179	138,338
MWh	133,298	134,919	122,296	108,636	100,498	106,222	116,665	109,754	106,309	98,594	103,919	110,660	1,351,771
kW	403,934	408,846	382,175	434,549	334,993	321,882	364,582	322,804	312,677	318,043	358,342	381,591	4,344,418
Revenue	$ 9,782,397	$ 9,793,235	$ 9,199,587	$ 10,240,945	$ 8,313,419	$ 8,099,706	$ 8,994,095	$ 8,127,220	$ 8,060,893	$ 8,068,922	$ 8,789,446	$ 9,132,897	$ 106,602,762
Service Classification No. 3													
Customer Months	37	37	37	37	37	37	37	37	37	37	37	37	444
MWh	31,372	30,445	22,252	32,281	26,768	23,367	26,447	25,469	23,473	27,335	26,532	27,434	323,176
kW	68,939	71,156	50,609	73,931	63,752	53,202	56,884	56,930	49,496	59,966	60,562	62,662	728,089
Revenue	$ 1,229,297	$ 1,265,023	$ 936,143	$ 1,309,458	$ 1,145,827	$ 975,728	$ 1,031,746	$ 1,033,691	$ 916,588	$ 1,084,837	$ 1,095,521	$ 1,128,780	$ 13,152,639
Service Classification No. 5													
Customer Months	3,733	3,733	3,733	3,733	3,733	3,733	3,681	3,681	3,681	3,681	3,681	3,681	44,484
MWh	740	820	910	1,050	1,130	1,250	1,180	980	950	840	760	670	11,280
Revenue	$ 278,632	$ 279,583	$ 280,522	$ 282,068	$ 282,979	$ 284,220	$ 283,737	$ 281,595	$ 281,282	$ 280,068	$ 279,118	$ 278,229	$ 3,372,033
Service Classification No. 6													
Customer Months	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	16,800
MWh	1,830	1,730	1,770	1,670	1,440	1,930	1,990	1,430	1,590	1,400	1,560	1,490	19,830
Revenue	$ 265,530	$ 257,959	$ 265,286	$ 249,095	$ 220,760	$ 279,801	$ 280,356	$ 213,936	$ 233,532	$ 212,184	$ 234,040	$ 225,031	$ 2,937,510
Service Classification No. 8													
Customer Months	212	212	212	212	212	212	212	212	212	212	212	212	2,544
MWh	710	790	870	1,010	1,090	1,200	1,140	950	930	820	740	650	10,900
Revenue	$ 557,334	$ 557,193	$ 557,062	$ 556,827	$ 556,686	$ 556,503	$ 556,216	$ 556,540	$ 556,568	$ 556,751	$ 556,892	$ 557,047	$ 6,681,617
Service Classification No. 13													
Substation													
Customer Months	4	4	4	4	4	4	4	4	4	4	4	4	48
MWh	9,460	9,500	8,730	8,800	8,410	8,140	9,120	7,630	8,840	8,530	8,720	8,910	104,790
kW	15,136	15,082	20,488	12,284	13,554	13,431	13,809	13,816	13,801	14,156	14,173	14,872	174,602
Revenue	$ 240,823	$ 240,129	$ 309,004	$ 204,457	$ 220,267	$ 219,111	$ 223,545	$ 223,574	$ 223,436	$ 228,317	$ 228,625	$ 237,588	$ 2,798,876
Service Classification No. 13													
Transmission													
Customer Months	6	6	6	6	6	6	6	6	6	6	6	6	72
MWh	58,910	57,260	53,180	52,080	49,700	48,810	48,880	45,340	50,040	50,580	52,460	53,720	620,960
kW	95,952	92,350	94,291	92,541	82,569	83,737	79,281	79,708	88,108	85,988	87,776	92,296	1,054,597
Revenue	$ 888,324	$ 859,418	$ 875,074	$ 862,311	$ 781,039	$ 790,294	$ 753,135	$ 756,606	$ 826,880	$ 808,041	$ 822,430	$ 858,963	$ 9,882,515
Total RDM Revenue Target	**$ 54,902,745**	**$ 56,545,909**	**$ 52,431,948**	**$ 50,434,784**	**$ 51,076,475**	**$ 55,202,421**	**$ 67,068,864**	**$ 64,718,581**	**$ 59,662,166**	**$ 53,882,045**	**$ 49,391,008**	**$ 47,900,829**	**$ 663,217,773**

Appendix R Sheet 5 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Electric RDM Targets
Rate Year 4 (Twelve Months Ended June 30, 2029)

	July 2028	August 2028	September 2028	October 2028	November 2028	December 2028	January 2029	February 2029	March 2029	April 2029	May 2029	June 2029	Total
Service Classification No. 1													
Customer Months	280,297	268,705	276,647	277,590	273,587	261,405	277,093	265,602	269,451	268,802	272,448	266,752	3,258,379
MWh	198,961	211,309	191,265	169,702	194,033	228,067	299,220	294,396	258,467	219,174	179,588	166,084	2,610,267
Revenue	$ 37,760,730	$ 39,351,370	$ 36,485,260	$ 33,208,920	$ 36,831,340	$ 41,729,180	$ 53,032,520	$ 51,993,870	$ 46,593,340	$ 40,557,730	$ 34,589,570	$ 32,371,730	$ 484,505,560
Service Classification No. 2													
Nondemand													
Customer Months	34,725	34,813	33,677	36,959	35,505	34,345	36,672	34,178	36,039	34,549	36,067	34,806	422,335
MWh	16,192	16,781	15,253	16,382	19,323	22,059	26,421	25,558	24,452	20,761	17,605	15,606	236,395
Revenue	$ 3,337,380	$ 3,415,880	$ 3,179,800	$ 3,444,250	$ 3,763,270	$ 4,068,120	$ 4,706,660	$ 4,504,580	$ 4,432,640	$ 3,910,010	$ 3,566,150	$ 3,267,220	45,595,960
Primary													
Customer Months	150	144	132	177	163	131	149	151	150	163	154	144	1,808
MWh	20,226	19,658	19,606	21,807	17,992	17,496	19,534	18,113	18,388	15,675	17,795	17,822	224,112
kW	53,237	49,123	47,812	57,401	43,883	42,694	44,409	45,275	41,796	41,263	46,841	40,523	554,257
Revenue	$ 811,335	$ 752,845	$ 728,535	$ 882,375	$ 693,985	$ 656,515	$ 693,918	$ 704,208	$ 659,378	$ 658,048	$ 727,308	$ 641,038	8,609,488
Secondary													
Customer Months	12,040	11,656	11,200	12,353	11,238	11,144	11,804	11,114	11,713	11,469	11,574	11,189	138,494
MWh	133,969	135,535	122,837	109,064	101,028	106,787	117,285	110,270	106,914	99,614	104,670	111,553	1,359,526
kW	405,928	410,718	383,882	436,288	336,787	323,600	366,525	324,387	314,490	321,285	360,903	384,613	4,369,406
Revenue	$ 9,875,293	$ 9,883,713	$ 9,280,803	$ 10,317,593	$ 8,388,543	$ 8,175,323	$ 9,078,204	$ 8,201,004	$ 8,138,374	$ 8,169,264	$ 8,878,764	$ 9,232,834	107,619,712
Service Classification No. 3													
Customer Months	37	37	37	37	37	37	37	37	37	37	37	37	444
MWh	31,393	30,465	22,245	32,237	26,758	23,375	26,435	25,440	23,462	27,405	26,548	27,478	323,243
kW	69,000	71,190	50,604	73,837	63,731	53,232	56,847	56,842	49,490	60,132	60,582	62,767	728,254
Revenue	$ 1,237,870	$ 1,273,410	$ 941,600	$ 1,316,070	$ 1,152,510	$ 982,070	$ 1,037,683	$ 1,038,993	$ 922,683	$ 1,094,913	$ 1,103,443	$ 1,138,213	13,239,458
Service Classification No. 5													
Customer Months	3,681	3,681	3,681	3,681	3,681	3,681	3,629	3,629	3,629	3,629	3,629	3,629	43,860
MWh	730	810	900	1,040	1,120	1,230	1,170	970	940	830	750	670	11,160
Revenue	$ 279,730	$ 280,770	$ 281,800	$ 283,510	$ 284,500	$ 285,890	$ 263,020	$ 260,650	$ 260,300	$ 258,960	$ 257,920	$ 256,920	3,253,970
Service Classification No. 6													
Customer Months	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	16,800
MWh	1,830	1,730	1,770	1,670	1,440	1,930	1,990	1,430	1,590	1,400	1,560	1,490	19,830
Revenue	$ 266,610	$ 258,980	$ 266,330	$ 250,080	$ 221,610	$ 280,940	$ 281,530	$ 214,780	$ 234,470	$ 213,010	$ 234,960	$ 225,910	2,949,210
Service Classification No. 8													
Customer Months	212	212	212	212	212	212	212	212	212	212	212	212	2,544
MWh	710	790	870	1,010	1,090	1,200	1,140	950	930	820	740	650	10,900
Revenue	$ 558,641	$ 558,691	$ 558,751	$ 558,851	$ 558,901	$ 558,981	$ 557,132	$ 557,002	$ 556,982	$ 556,902	$ 556,852	$ 556,792	6,694,477
Service Classification No. 13													
Substation													
Customer Months	4	4	4	4	4	4	4	4	4	4	4	4	48
MWh	9,460	9,500	8,730	8,800	8,410	8,140	9,120	7,630	8,840	8,530	8,720	8,910	104,790
kW	15,136	15,082	20,488	12,284	13,554	13,431	13,809	13,816	13,801	14,156	14,173	14,872	174,602
Revenue	$ 246,770	$ 246,070	$ 315,540	$ 210,090	$ 226,040	$ 224,870	$ 229,190	$ 229,220	$ 229,080	$ 234,000	$ 234,310	$ 243,350	2,868,530
Service Classification No. 13													
Transmission													
Customer Months	6	6	6	6	6	6	6	6	6	6	6	6	72
MWh	58,910	57,260	53,180	52,080	49,700	48,810	48,880	45,340	50,040	50,580	52,460	53,720	620,960
kW	96,952	93,350	95,291	93,541	83,569	84,737	80,281	80,708	89,108	86,988	88,776	93,296	1,066,597
Revenue	$ 919,630	$ 890,400	$ 906,230	$ 893,310	$ 811,140	$ 820,500	$ 782,820	$ 786,330	$ 857,360	$ 838,330	$ 852,880	$ 889,820	10,248,750
Total RDM Revenue Target	**$ 55,293,989**	**$ 56,912,129**	**$ 52,944,649**	**$ 51,365,049**	**$ 52,931,839**	**$ 57,782,389**	**$ 70,662,677**	**$ 68,490,637**	**$ 62,884,607**	**$ 56,491,167**	**$ 51,002,157**	**$ 48,823,827**	**$ 685,585,115**

Central Hudson Gas & Electric Corporation

Cases 24-E-0461 & 24-G-0462

Electric SC 13 RDM Example

	Example Customer 1	**Example Customer 2**	**Example Customer 3**	**Example Customer 4**	**Example Month 1 Total**	**Example Month 2**	**Example Month 3**	**Example Month 4**	**Example Month 5**	**Example Month 6**	**Total 6 Months**
Cust Chg	$ 15,500	$ 15,500	$ 9,700	$ 9,700							
$/kW	$ 7.69	$ 7.69	$ 12.26	$ 12.26							
Target											
kW	25,562	500	901	-							
Revenue	$ 212,072	$ 19,345	$ 20,746	$ -	**$ 252,163**						
Actual											
kW	23,457	-	500	750							
Revenue	$ 195,884	$ -	$ 15,830	$ 18,895	**$ 230,609**						
SC 13 Lost/Gained Customer Excluded from Reconciliation:	N	**Y**	N	**Y**							
Exclusion from Target	$ -	$ 19,345	$ -	$ -							
Exclusion from Actual	$ -	$ -	$ -	$ 18,895							
SC 13 Change in Billed Demand of >= 40%	N	N	**Y**	N							
Exclusion from Target	$ -	$ -	$ 20,746	$ -							
Exclusion from Actual	$ -	$ -	$ 15,830	$ -							
SC 13 Adjusted Target (A - C - D)	$ 212,072	$ -	$ -	$ -	**$ 212,072**	$ 650,000	$ 670,000	$ 625,000	$ 635,000	$ 665,000	
SC 13 Adjusted Actual (B - C - D)	$ 195,884	$ -	$ -	$ -	**$ 195,884**	$ 615,000	$ 665,000	$ 690,000	$ 680,000	$ 675,000	
5% Deadband Applied to Adjusted SC 13 Target (E*1.05; E*0.95)				Upper	**$ 222,675**	$ 682,500	$ 703,500	$ 656,250	$ 666,750	$ 698,250	
				Lower	**$ 201,468**	$ 617,500	$ 636,500	$ 593,750	$ 603,250	$ 631,750	
SC 13 Over/(Under) Outside 5% Deadband (F - G)					**$ (5,584)**	$ (2,500)	$ -	$ 33,750	$ 13,250	$ -	**$ 38,916**
SC 13 Monthly Over/(Under) as % of Adjusted Target					**-2.6%**	-0.4%	0.0%	5.4%	2.1%	0.0%	
SC 13 Constrained to 2.5% Monthly Over/(Under)					**$ (5,302)**	$ (2,500)	$ -	$ 15,625	$ 13,250	$ -	**$ 21,073**
Carryover of Prior Month Over/(Under) Outside 2.5% Constraint					**$ -**	$ (282)	$ -	$ -	$ 2,625	$ 15,500	**$ 17,843**
Current + Prior Month Over/(Under)					**$ (5,302)**	$ (2,782)	$ -	$ 15,625	$ 15,875	$ 15,500	**$ 38,916**
					-2.5%	-0.4%	0.0%	2.5%	2.5%	2.3%	

Appendix R Sheet 7 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Gas RDM Targets

S.C. Nos. 1 & 12

	12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year 3
Revenue Forecast*	$ 105,760,533	$ 115,059,137	$ 125,201,365
Customer Forecast	76,753	76,941	77,101
Mcf	5,568,167	5,545,187	5,521,919

S.C. Nos. 2, 6, 11 & 13

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Forecast*	$ 69,396,373	$ 74,899,775	$ 81,205,530
Customer Forecast	12,406	12,342	12,306
Mcf	10,114,372	10,029,466	9,963,653

*Base revenue excluding MFC revenue
**Please refer to sum of monthly values shown on Appendix R Sheet 7-9.

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rate Year 1 (Twelve Months Ended June 30, 2026) RDM Targets

	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Total
S.C. Nos. 1 & 12													
Revenue Forecast*	$ 2,778,033	$ 2,591,387	$ 3,086,853	$ 5,137,046	$ 9,165,864	$ 13,236,802	$ 16,025,387	$ 16,550,299	$ 14,629,883	$ 11,575,101	$ 6,983,158	$ 4,000,719	$ 105,760,533
Customer Forecast	76,591	76,454	76,665	76,617	76,742	76,621	76,613	76,607	77,001	77,773	76,630	76,719	76,753
Mcf	60,068	47,377	81,443	219,050	487,964	759,967	946,150	981,245	852,417	647,391	342,344	142,751	5,568,167
S.C. Nos. 2, 6, & 13													
Revenue Forecast*	$ 2,232,276	$ 2,072,839	$ 2,401,246	$ 3,445,542	$ 5,526,955	$ 7,579,737	$ 9,106,288	$ 9,251,743	$ 8,266,024	$ 6,497,064	$ 4,390,067	$ 2,839,287	$ 63,609,067
Customer Forecast	12,720	12,349	12,615	12,408	12,504	12,431	12,619	12,432	12,236	11,374	12,640	12,451	12,398
Mcf	232,762	213,292	257,142	400,514	684,153	964,834	1,172,335	1,193,533	1,059,924	823,358	528,026	317,367	7,847,240
S.C. No. 11 (Excl S.C. No. 11 EG)													
Revenue Forecast	$ 454,247	$ 444,903	$ 455,063	$ 470,676	$ 500,529	$ 511,945	$ 527,916	$ 515,377	$ 509,399	$ 481,299	$ 466,507	$ 449,445	$ 5,787,306
Customer Forecast	8	8	8	8	8	8	8	8	8	8	8	8	8
Mcf	136,342	79,538	114,658	155,626	239,115	267,448	310,609	276,732	256,871	188,175	147,462	94,556	2,267,132

*Base revenue excluding MFC revenue

Appendix R Sheet 9 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rate Year 2 (Twelve Months Ended June 30, 2027) RDM Targets

S.C. Nos. 1 & 12

	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Total
Revenue Forecast*	$ 2,928,459	$ 2,730,573	$ 3,268,160	$ 5,539,186	$ 9,978,988	$ 14,479,396	$ 17,543,983	$ 18,127,258	$ 15,998,875	$ 12,627,263	$ 7,561,929	$ 4,275,067	$ 115,059,137
Customer Forecast	76,777	76,812	76,840	76,891	76,925	76,843	76,772	76,792	77,149	77,914	76,739	76,843	76,941
Mcf	57,330	44,761	78,755	217,024	486,238	759,184	945,054	980,418	850,865	645,462	339,915	140,181	5,545,187

S.C. Nos. 2, 6, & 13

	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Total
Revenue Forecast*	$ 2,403,376	$ 2,262,133	$ 2,543,369	$ 3,702,923	$ 5,935,600	$ 8,230,948	$ 9,827,325	$ 10,059,424	$ 8,927,826	$ 7,026,256	$ 4,697,291	$ 3,019,935	$ 68,636,406
Customer Forecast	12,575	12,421	12,466	12,387	12,371	12,424	12,498	12,425	12,143	11,341	12,543	12,417	12,334
Mcf	231,953	215,375	250,645	395,208	673,530	959,255	1,157,915	1,187,452	1,047,866	815,271	518,122	309,742	7,762,334

S.C. No. 11 (Excl S.C. No. 11 EG)

	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Total
Revenue Forecast	$ 493,984	$ 477,900	$ 489,821	$ 507,993	$ 542,830	$ 556,065	$ 574,679	$ 560,077	$ 553,130	$ 520,402	$ 503,244	$ 483,245	$ 6,263,369
Customer Forecast	8	8	8	8	8	8	8	8	8	8	8	8	8
Mcf	136,342	79,538	114,658	155,626	239,115	267,448	310,609	276,732	256,871	188,175	147,462	94,556	2,267,132

*Base revenue excluding MFC revenue

Appendix R Sheet 10 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rate Year 3 (Twelve Months Ended June 30, 2028) RDM Targets

S.C. Nos. 1 & 12

	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Total
Revenue Forecast*	$ 3,100,900	$ 2,881,435	$ 3,475,648	$ 5,980,698	$ 10,861,928	$ 15,816,188	$ 19,184,887	$ 19,824,463	$ 17,486,553	$ 13,782,912	$ 8,211,796	$ 4,593,959	$ 125,201,365
Customer Forecast	76,886	76,915	76,969	77,026	77,056	77,010	76,938	76,961	77,332	78,114	76,939	77,061	77,101
Mcf	54,523	41,941	76,046	214,687	484,226	757,856	943,949	979,245	849,602	644,073	337,939	137,832	5,521,919

S.C. Nos. 2, 6, & 13

	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Total
Revenue Forecast*	$ 2,512,560	$ 2,372,235	$ 2,703,033	$ 3,978,838	$ 6,426,364	$ 8,960,423	$ 10,695,412	$ 10,979,406	$ 9,726,780	$ 7,657,363	$ 5,099,490	$ 3,268,957	$ 74,380,862
Customer Forecast	12,456	12,367	12,402	12,348	12,324	12,407	12,455	12,420	12,115	11,331	12,526	12,423	12,298
Mcf	222,183	206,851	244,670	389,315	667,073	954,033	1,150,703	1,183,324	1,042,695	812,008	515,383	308,283	7,696,521

S.C. No. 11 (Excl S.C. No. 11 EG)

	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Total
Revenue Forecast	$ 542,305	$ 528,671	$ 539,307	$ 556,287	$ 588,439	$ 601,005	$ 616,877	$ 603,480	$ 597,231	$ 566,870	$ 551,073	$ 533,124	$ 6,824,668
Customer Forecast	8	8	8	8	8	8	8	8	8	8	8	8	8
Mcf	136,342	79,538	114,658	155,626	239,115	267,448	310,609	276,732	256,871	188,175	147,462	94,556	2,267,132

*Base revenue excluding MFC revenue

Appendix R Sheet 11 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rate Year 4 (Twelve Months Ended June 30, 2029) RDM Targets

S.C. Nos. 1 & 12

	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Total
Revenue Forecast*	$ 3,082,440	$ 2,864,850	$ 3,460,300	$ 5,997,940	$ 10,948,840	$ 15,972,530	$ 19,390,770	$ 20,036,320	$ 17,663,870	$ 13,912,130	$ 8,261,110	$ 4,593,430	$ 126,184,530
Customer Forecast	77,039	77,150	77,204	77,260	77,307	77,263	77,208	77,231	77,602	78,401	77,226	77,348	77,353
Mcf	51,841	39,235	73,481	212,700	483,066	757,389	944,067	979,289	849,221	643,369	336,285	135,548	5,505,491

S.C. Nos. 2, 6, & 13

	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Total
Revenue Forecast*	$ 2,507,950	$ 2,376,690	$ 2,707,680	$ 3,994,880	$ 6,470,560	$ 9,031,650	$ 10,779,250	$ 11,078,990	$ 9,805,550	$ 7,723,920	$ 5,137,160	$ 3,288,660	$ 74,902,940
Customer Forecast	12,437	12,375	12,397	12,343	12,324	12,411	12,451	12,430	12,115	11,337	12,533	12,438	12,299
Mcf	220,215	205,768	243,332	387,808	665,775	952,750	1,148,960	1,182,766	1,041,570	811,539	515,155	308,337	7,683,975

S.C. No. 11 (Excl S.C. No. 11 EG)

	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Total
Revenue Forecast	$ 545,805	$ 531,075	$ 542,485	$ 560,585	$ 594,925	$ 608,285	$ 626,705	$ 612,235	$ 605,425	$ 572,695	$ 555,575	$ 536,205	$ 6,891,995
Customer Forecast	8	8	8	8	8	8	8	8	8	8	8	8	8
Mcf	136,342	79,538	114,658	155,626	239,115	267,448	310,609	276,732	256,871	188,175	147,462	94,556	2,267,132

*Base revenue excluding MFC revenue

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Gas SC 11 RDM Example

	Example Customer 1	Example Customer 2	Example Customer 3	Example Customer 4	Example Month 1 Total	Example Month 2	Example Month 3	Example Month 4	Example Month 5	Example Month 6	Total 6 Months
A Target											
MDQ	7,500	350	5,000	-							
Ccf	1,050,000	75,000	900,000	-							
Revenue	$ 84,955	$ 11,156	$ 98,440	$ -	**$ 194,551**						
B Actual											
MDQ	8,000	-	2,900	750							
Ccf	1,400,000	-	750,000	145,000							
Revenue	$ 95,140	$ -	$ 65,074	$ 21,610	**$ 181,824**						
C SC 11 Lost/Gained Customer Excluded from Reconciliation:	N	**Y**	N	**Y**							
Exclusion from Target	$ -	$ 11,156	$ -	$ -							
Exclusion from Actual	$ -	$ -	$ -	$ 21,610							
**** SC 11 Change in Billed MDQ of >= 40%**	N	N	**Y**	N							
Exclusion from Target	$ -	$ -	$ 98,440	$ -							
Exclusion from Actual	$ -	$ -	$ 65,074	$ -							
E SC 11 Adjusted Target (A - C - D)	$ 84,955	$ -	$ -	$ -	**$ 84,955**	$ 100,000	$ 95,000	$ 88,000	$ 80,000	$ 67,000	
F SC 11 Adjusted Actual (B - C - D)	$ 95,140	$ -	$ -	$ -	**$ 95,140**	$ 93,000	$ 90,000	$ 79,000	$ 74,000	$ 70,000	
G 5% Deadband Applied to Adjusted SC 11 Target (E*1.05; E*0.95)				Upper	**$ 89,203**	$ 105,000	$ 99,750	$ 92,400	$ 84,000	$ 70,350	
				Lower	**$ 80,707**	$ 95,000	$ 90,250	$ 83,600	$ 76,000	$ 63,650	
H SC 11 Over/(Under) Outside 5% Deadband (F - G)					**$ 5,937**	$ (2,000)	$ (250)	$ (4,600)	$ (2,000)	$ -	**$ (2,913)**
I SC 11 Monthly Over/(Under) as % of Adjusted Target					**7.0%**	-2.0%	-0.3%	-5.2%	-2.5%	0.0%	
J											
SC 11 Constrained to 2.5% Monthly Over/(Under)					**$ 2,124**	$ (2,000)	$ (250)	$ (2,200)	$ (2,000)	$ -	**$ (4,326)**
Carryover of Prior Month Over/(Under) Outside 2.5% Constraint					**$ -**	$ 3,813	$ -	$ -	$ -	$ (1,675)	**$ 2,138**
Current + Prior Month Over/(Under)					**$ 2,124**	$ 1,813	$ (250)	$ (2,200)	$ (2,000)	$ (1,675)	**$ (2,188)**
					2.5%	1.8%	-0.3%	-2.5%	-2.5%	-2.5%	

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Gas MFC Targets

MFC-1 (S.C. Nos. 1, 12 & 16)

	12 Months Ending Jun-26 Rate Year 1	12 Months Ending Jun-27 Rate Year 2	12 Months Ending Jun-28 Rate Year 3
Revenue Target	$ 983,360	$ 983,210	$ 982,900

MFC-2 (S.C. Nos. 2, 6, 13 & 15)

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Target	$ 1,381,100	$ 1,384,780	$ 1,385,370

Appendix R Sheet 14 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rate Year 1 (Twelve Months Ended June 30, 2026) MFC Targets

MFC-1 (S.C. Nos. 1, 12)

	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Total
Revenue Target	$ 10,610	$ 8,370	$ 14,390	$ 38,690	$ 86,170	$ 134,220	$ 167,090	$ 173,290	$ 150,530	$ 114,330	$ 60,460	$ 25,210	$ 983,360

MFC-2 (S.C. Nos. 2, 6, 13)

	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Total
Revenue Target	$ 40,950	$ 37,540	$ 45,260	$ 70,470	$ 120,410	$ 169,820	$ 206,320	$ 210,070	$ 186,540	$ 144,920	$ 92,950	$ 55,850	$ 1,381,100

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rate Year 2 (Twelve Months Ended June 30, 2027) MFC Targets

	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Total
MFC-1 (S.C. Nos. 1, 12)													
Revenue Target	$ 10,170	$ 7,940	$ 13,960	$ 38,490	$ 86,210	$ 134,610	$ 167,560	$ 173,840	$ 150,870	$ 114,430	$ 60,270	$ 24,860	$ 983,210
MFC-2 (S.C. Nos. 2, 6, 13)													
Revenue Target	$ 41,380	$ 38,410	$ 44,720	$ 70,510	$ 120,150	$ 171,130	$ 206,580	$ 211,840	$ 186,920	$ 145,430	$ 92,440	$ 55,270	$ 1,384,780

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rate Year 3 (Twelve Months Ended June 30, 2028) MFC Targets

MFC-1 (S.C. Nos. 1, 12)

	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Total
Revenue Target	$ 9,710	$ 7,470	$ 13,540	$ 38,210	$ 86,180	$ 134,900	$ 168,030	$ 174,300	$ 151,230	$ 114,640	$ 60,150	$ 24,540	$ 982,900

MFC-2 (S.C. Nos. 2, 6, 13)

	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Total
Revenue Target	$ 40,000	$ 37,220	$ 44,040	$ 70,080	$ 120,080	$ 171,720	$ 207,130	$ 213,000	$ 187,690	$ 146,150	$ 92,770	$ 55,490	$ 1,385,370

Appendix R Sheet 17 of 17

Central Hudson Gas & Electric Corporation
Cases 24-E-0461 & 24-G-0462
Rate Year 4 (Twelve Months Ended June 30, 2029) MFC Targets

MFC-1 (S.C. Nos. 1, 12)

	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Total
Revenue Target	$ 9,220	$ 6,980	$ 13,080	$ 37,850	$ 85,990	$ 134,810	$ 168,040	$ 174,300	$ 151,160	$ 114,510	$ 59,850	$ 24,120	$ 979,910

MFC-2 (S.C. Nos. 2, 6, 13)

	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Total
Revenue Target	$ 39,630	$ 37,040	$ 43,800	$ 69,810	$ 119,840	$ 171,500	$ 206,810	$ 212,890	$ 187,470	$ 146,070	$ 92,730	$ 55,500	$ 1,383,090

Central Hudson Gas and Electric Corporation
Cases 24-E-0461 and 24-G-0462
Electric Reliability Performance Mechanism

Electric Reliability

Operation of Mechanism

The calendar year performance metrics adopted herein are described below and will remain in effect until reset by the Commission. The measurement periods for the reliability mechanism metrics will be on a calendar year basis.

The reliability mechanism establishes the following calendar year performance metrics:

(a) threshold standards, consisting of system-wide performance targets for frequency and duration of electric service interruption defined as:

1. CAIDI - Customer Average Interruption Duration Index. The average interruption duration time (customers-hours interrupted) for those customers that experience an interruption during the year.[1]

2. SAIFI - System Average Interruption Frequency Index. The average number of times that a customer is interrupted per the total number of customers served during the year.[2]

The electric service annual metric for SAIFI shall be a 30 basis point (electric, pre-tax) potential negative revenue adjustment for failure to achieve an annual SAIFI target of 1.30 for each calendar year. The electric service annual metric for CAIDI shall be a 30 basis point (electric, pre-tax) potential negative revenue adjustment for failure to achieve an annual CAIDI of 2.50 hours for each calendar year.

(b) The Quarterly Meeting process will continue.

All revenue adjustments related to this reliability mechanism will come from shareholder funds and will be deferred and credited for the benefit of ratepayers through the Rate Adjustment Mechanism or as ordered in a subsequent rate case.

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[1] CAIDI shall be calculated using the methodology set forth in Case 02-E-1240, Proceeding on the Motion of the Commission to Examine Electric Service Standards and Methodologies, Order Adopting Changes to Standards on Reliability of Electric Service (issued October 12, 2004), Attachment 1, pp. 2-3.

[2] SAIFI shall be calculated using the methodology set forth in Case 02-E-1240, Proceeding on the Motion of the Commission to Examine Electric Service Standards and Methodologies, Order Adopting Changes to Standards on Reliability of Electric Service (issued October 12, 2004), Attachment 1, p. 2.

Exclusions

The following exclusions will be applicable to operating performance under this reliability performance mechanism:

(a) Any outages resulting from a major storm, as defined in 16 NYCRR Part 97(1)(c) (i.e., at least 10% of the customers interrupted within an operating area or customers out of service for at least 24 hours), except as otherwise noted.

(b) Any incident resulting from a catastrophic event beyond the control of the Company, including but not limited to plane crash, water main break, or natural disasters (e. g., hurricanes, floods, earthquakes, tornadoes, microbursts).

(c) Any incident where problems beyond the Company's control involving generation or the bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as a result of unsatisfactory performance by the Company.

The Company shall use the following process for potential exclusions, other than major storms:

1. The Company will provide preliminary notice and supporting documentation for potential annual report exclusions to the Secretary and the Director of the Office of Resilience and Emergency Preparedness for review within 45 days of the event. The Company will continue to submit supporting documentation for all exclusions in its annual reliability report.

2. The Company may petition the Commission for exemption from the requirements and/or revenue adjustment associated with the RPM metrics, on a case-by-case basis. Such petition must be filed in Case 24-E-0461 after the close of the year to which it refers and no later than the date the Company files its annual reliability report.

Central Hudson Gas and Electric Corporation
Cases 24-E-0461 and 24-G-0462
Electric Reliability Performance Mechanism

Reporting

The Company will prepare its annual report on its calendar year performance under this reliability mechanism. The annual reports will be filed by March 31st of each year to the Secretary in the annual case created by the Department for consideration of all the electric utilities' annual reliability reports.

The reports will state the:

(a) Company's annual system-wide performance under the reliability performance mechanism and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;

(b) Whether any exclusions should apply, the basis for requesting each exclusion, and adequate support for all requested exclusions.

Appendix T
Central Hudson Gas and Electric Corporation
Cases 24-E-0461 and 24-G-0462

Gas Safety Metrics

Leak Prone Pipe (LPP)				
Calendar Year	**2025**	**2026**	**2027**	**2028**
LPP Removal (Miles)	15	15	15	Remaining
NRA (BPs)	15	15	15	2 BPs per mile remaining

Leak Management Targets					
	Targets	**NRA(BPs)**	**PRA (BPs)**	**Annual Maximum NRA (BPs)**	**Annual Maximum PRA (BPs)**
Year End Total Leak Backlog (Types 1, 2, 2A, &3)	≥ 56	15	-	15	6
	≥ 50 - ≤ 55	6	-		
	≥ 30 - ≤ 49	0	-		
	≥ 15 - ≤ 29	-	2*		
	≥ 6 - ≤ 14	-	4*		
	≤ 5	-	6*		

* For Central Hudson to earn PRA, the year end backlog of repairable leaks (Type 1, 2 & 2A) must be no more than six leaks.

Damage Prevention		
Total Damage per 1,000 One-Call Tickets	**NRA (BPs)**	**PRA (BPs)**
≥ 1.70	20	-
≥ 1.55 - < 1.70	10	-
≥ 1.45 - < 1.55	5	-
≥ 1.05 - < 1.45	0	0
≥ 1.00 - < 1.05	0	2
≥ 0.95 - < 1.00	0	4
< 0.95	0	6

Emergency Response					
Response Time	**Targets (%)**	**NRA (BPs)**	**Max NRA BPs/Year**	**PRA BPs**	**Max PRA BPs/Year**
30 Minutes	< 75	12	25	-	6
	≥ 75 - < 88	-		-	
	≥ 88 - < 92	-		2	
	≥ 92 - < 95	-		4	
	≥ 95	-		6	
45 Minutes	< 90	8		-	
60 Minutes	< 95	5		-	

Non Compliance with Pipeline Safety Regulations					
Category	**Occurrences**	**NRA BPs**	**Max NRA BPs/Year**	**PRA BPs**	**Max PRA BPs/Year**
High Risk					
Records	0-5	0	75	NA	NA
Records	6-10	1/2		NA	NA
Records	11+	1		NA	NA
Field	0 - 5	1/2		NA	NA
	6 +	1		NA	NA
Other Risk				NA	NA
Records	0-10	0		NA	NA
Records	11+	1/4		NA	NA
Field	All	1/4		NA	NA

Gas Safety Enhancement Programs			
Safety Program	**Target (LPS)**	**PRA BPs/event**	**Max PRA BPs/Year**
Utilizing re-compression method to capture methane from escaping to the atmosphere during transmission and/or valves replacement projects	-	-	-
Municipalities Gas Emergency Drills	2	4	8
Leak Prone Services Replacement Program	≥ 211	4	4

Gas Safety Violations Performance Measure:

Procedure and List of High and Other Regulatory Provisions

Applicability

The compliance measure applies to instances of non-compliance (occurrences or violations) of certain gas pipeline safety-related regulations set forth below that are identified and included in Staff's record and field audit letters. The categorization of instances of non-compliance as High Risk or Other Risk is for administrative purposes only.

The compliance measure covers the calendar years associated with the term of the rate plan set forth in the Joint Proposal, i.e., 2026, 2027, and 2028, and shall remain in effect thereafter until changed by the Commission in a subsequent Central Hudson rate case.

Targets

Central Hudson Gas & Electric Corporation, herein referred to as "the operator," will incur negative revenue adjustments for each High Risk and Other Risk instance of non-compliance, as set forth in the following tables:

2026 through 2028 Field Audits		
Associated Risk	Target (Number of Instances of Non-Compliance)	Negative Revenue Adjustment (Basis Points per Instance of Non-Compliance)
High Risk	0 to 5	0.5
	6 +	1
Other Risk	All	0.25

For field audits, only actions performed or failures to take actions required to be performed by the operator in the calendar year the audit is conducted may constitute an instance of non-compliance under this measure.

2026 through 2028 Record Audits		
Associated Risk	Target (Number of Instances of Non-Compliance)	Negative Revenue Adjustment (Basis Points per Instance of Non-Compliance)
High Risk	0 to 5	0
High Risk	6 to 10	0.50
High Risk	11 +	1.00
Other Risk	11 +	0.25

For record audits, only documentation that the operator is required, but fails, to generate during the calendar year prior to the calendar year in which the record audit is conducted may constitute an instance of non-compliance under this measure. Unless it is a continuing violation from prior years, in which case it may also constitute an instance of non-compliance under this measure.

Field and Record Audits

On a calendar year basis, Staff conducts field and record audits to determine the operator's compliance with the pipeline safety regulations contained in 16 NYCRR Parts 10, 232, 255, 257, 258, 259, 261, 262, 293, 420, 733, and 753, Title 49 of United States Code of Federal Regulations (49 CFR) Part 193, and the relevant statutory provisions in General Business Law and Public Service Law. At the conclusion of each audit, Staff will present its findings at a compliance meeting to the operator.

The operator shall have ten business days from the date of the compliance meeting to cure any identified document deficiency. Only official operator records, as defined in the operator's operating and maintenance procedures, shall be considered as a cure to a document deficiency. Staff shall provide the operator with the field and record audit letters. Only instances of non-compliance identified and included in Staff's field and record audit letters shall be considered for the compliance measure.

The field and record audit letters require, if applicable, that the operator respond within thirty days of the audit letter detailing what actions have and/or will be taken by the operator to remediate the instances of non-compliance and to address Staff's concerns, and to prevent future reoccurrences. The operator's response may also include any disputes related to the instance of non-compliance, including but not limited to, sufficient arguments regarding the appropriateness of applying a negative revenue adjustment. The operator shall provide its response to an audit letter to the Chief of Pipeline Safety.

In addition, the operator should address instances of non-compliance of a single regulation in excess of ten per record audit per calendar year through a remediation plan, the operator shall provide to the Chief of Pipeline Safety the remediation plan within ninety days of Staff's field or record audit letters. The remediation plan shall include, at a minimum, an analysis for the instances of non-compliance, and an explanation of how the instances of non-compliance will be resolved, including the dates by which the instances of non-compliance will be brought into compliance or, where appropriate, when remedial actions will be taken to prevent future recurrence.

Staff then will review and consider each instance of non-compliance for applicability with the compliance measure on a case-by-case basis. Instances of non-compliance subject to a separate penalty proceeding under Public Service Law §25 or §25-a, and instances of non-compliance for which sufficient arguments have been raised regarding the appropriateness of a negative revenue adjustment, will be excluded from consideration. Once reviewed and the circumstances considered, Staff shall file the negative revenue adjustment letter in Case 24-G-0462. Copies of the staff audit letters, any operator responses, and any remediation plans will be submitted in Case 24-G-0462 when the negative revenue adjustment letter is submitted.

<u>Negative Revenue Adjustments</u>

The operator will incur negative revenue adjustments for each High Risk and Other Risk instance of non-compliance up to a combined maximum of seventy-five basis points per calendar year, as per the above targets.

The number of instances of non-compliance, for any applicable regulation, may be capped at ten per record audit per calendar year provided a remediation plan as described above is filed with the Chief of Pipeline Safety. If the operator files a remediation plan, it shall include, at a minimum, an analysis for the instances of non-compliance, and an explanation of how the non-compliance with the applicable regulation will be resolved, including the dates by which the instance of non-compliance will be brought into compliance or, where appropriate, when remedial actions will be taken to prevent future recurrence.

Remediation plans shall be filed with the Chief of Pipeline Safety within ninety days of Staff's field or record audit letters. If the operator fails to file a remediation plan or fails to comply with the provisions of its remediation plan, those instances of non-compliance in excess of ten shall be incorporated with the remainder of the instances of non-compliance being considered under this measure.

If the operator elects to dispute any instances of non-compliance or negative revenue adjustments, or to seek exclusions of certain non-compliances based on extenuating circumstances, the operator shall file a petition within sixty days of Staff's negative revenue adjustment letter in Case 24-G-0462. For those disputed items or exclusions, the operator will not incur a negative revenue adjustment until the Commission has issued a determination.

The operator does not waive its right to seek judicial appeal of any Commission determination under applicable law. Should the operator elect to seek judicial appeal of any Commission determination under applicable law, the operator will not incur a negative revenue adjustment until such time that the judicial review is complete, and a determination rendered.

If an instance of non-compliance is the subject of a separate penalty proceeding under Public Service Law §25 or §25-a, the instance of non-compliance shall not be considered for the compliance measure.

If an instance of non-compliance has a corresponding procedural instance of non-compliance under 16 NYCRR §255.603(d), non-compliance with both provisions shall be considered as a single instance of non-compliance for the compliance measure.

<u>Risk Rankings</u>

The pipeline safety regulations are contained in 16 NYCRR Parts 10, 232, 255, 257, 258, 259, 261, 262, 293, 420, 733, and 753, 49 CFR Part 193, and the relevant statutory provisions contained in General Business Law and Public Service Law. Set forth below are the high risk and other risk pipeline safety regulations being considered for the compliance measure.

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	5	(g)	Class Locations	High
16	III	C	255	14	(a)	Conversion to Service Subject to this Part	High
16	III	C	255	14	(b)	Conversion to Service Subject to this Part	Other
16	III	C	255	17	All	Preservation of Records	Other
16	III	C	255	18	(a),(c)	Notifications and Reports	High
16	III	C	255	53	All	Materials - General	High
16	III	C	255	65	All	Materials - Transportation of Pipe	High
16	III	C	255	67	(a),(b)	Records - Material Properties	High
16	III	C	255	103	All	Pipe Design - General	High
16	III	C	255	127	(a),(b)	Records - Pipe Design	High
16	III	C	255	143	All	Design of Pipeline Components - General Requirements	High
17	III	C	255	153	(e)	Components fabricated by welding	High
16	III	C	255	159	All	Design of Pipeline Components - Flexibility	High
16	III	C	255	161	All	Design of Pipeline Components - Supports and Anchors	High
16	III	C	255	163	All	Compressor Stations - Design and Construction	Other
16	III	C	255	165	All	Compressor Stations - Liquid Removal	Other
16	III	C	255	167	All	Compressor Stations - Emergency Shutdown	High
16	III	C	255	169	All	Compressor Stations - Pressure Limiting Devices	High
16	III	C	255	171	All	Compressor Stations - Additional Safety Equipment	Other
16	III	C	255	173	All	Compressor Stations - Ventilation	High
16	III	C	255	179	All	Valves on Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	181	All	Distribution Line Valves	High
16	III	C	255	183	All	Vaults - Structural Design Requirements	High
16	III	C	255	185	All	Vaults - Accessibility	Other
16	III	C	255	187	All	Vaults - Sealing, Venting, and Ventilation	Other
16	III	C	255	189	All	Vaults - Drainage and Waterproofing	High
16	III	C	255	190	All	Calorimeter or Calorimixer Structures	Other
16	III	C	255	191	All	Design Pressure of Plastic Fittings	Other
16	III	C	255	193	All	Valve Installation in Plastic Pipe	Other
16	III	C	255	195	All	Protection Against Accidental Overpressuring	High
16	III	C	255	197	All	Control of the Pressure of Gas Delivered from High Pressure Distribution Systems	High
16	III	C	255	199	All	Requirements for Design of Pressure Relief and Limiting Devices	High
16	III	C	255	201	All	Required Capacity of Pressure Relieving and Limiting Stations	High
16	III	C	255	203	All	Instrument, Control, and Sampling Piping and Components	Other
16	III	C	255	205	(a),(b)	Records - Pipeline Components	High
16	III	C	255	225	All	Qualification of Welding Procedures	High
16	III	C	255	227	All	Qualification of Welders	High
16	III	C	255	229	All	Limitations On Welders	Other
16	III	C	255	230	All	Quality Assurance Program	Other
16	III	C	255	231	All	Welding - Protection from Weather	High
16	III	C	255	233	All	Welding - Miter Joints	High
16	III	C	255	235	All	Preparation for Welding	High
16	III	C	255	237	All	Welding - Preheating	Other
16	III	C	255	239	All	Welding - Stress Relieving	Other
16	III	C	255	241	(a),(b)	Inspection and Test of Welds	High
16	III	C	255	241	(c)	Inspection and Test of Welds	Other
16	III	C	255	243	(a),(b),(c),(d),(e)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	243	(f)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (862 kPa) or More	Other

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	244	All	Welding Inspector	High
16	III	C	255	245	All	Welding - Repair or Removal of Defects	High
16	III	C	255	273	All	Joining of Materials other than by Welding - General	High
16	III	C	255	279	All	Joining of Materials other than by Welding - Copper Pipe	High
16	III	C	255	281	All	Joining of Materials other than by Welding - Plastic Pipe	High
16	III	C	255	283	All	Plastic Pipe - Qualifying Joining Procedures	Other
16	III	C	255	285	(a),(b),(d)	Plastic Pipe - Qualifying Persons to make Joints	High
16	III	C	255	285	(c),(e),(f)	Plastic Pipe - Qualifying Persons to make Joints	Other
16	III	C	255	287	All	Plastic Pipe - Inspection of Joints	Other
16	III	C	255	302	All	Notification Requirements	High
16	III	C	255	303	All	Compliance with Construction Standards	High
16	III	C	255	305	All	Inspection - General	High
16	III	C	255	307	All	Inspection of Materials	High
16	III	C	255	309	All	Repair of Steel Pipe	High
16	III	C	255	311	All	Repair of Plastic Pipe	High
16	III	C	255	313	(a),(b),(c)	Bends and Elbows	High
16	III	C	255	313	(d)	Bends and Elbows	Other
16	III	C	255	315	All	Wrinkle Bends in Steel Pipe	High
16	III	C	255	317	All	Protection from Hazards	Other
16	III	C	255	319	All	Installation of Pipe in a Ditch	Other
16	III	C	255	321	All	Installation of Plastic Pipe	High
16	III	C	255	323	All	Casing	Other
16	III	C	255	325	All	Underground Clearance	High
16	III	C	255	327	All	Cover	Other
16	III	C	255	353	All	Customer Meters and Regulators - Location	Other
16	III	C	255	355	All	Customer Meters and Regulators - Protection from Damage	Other
16	III	C	255	357	(a),(b),(c)	Customer Meters and Service Regulators - Installation	Other
16	III	C	255	357	(d)	Customer Meters and Service Regulators - Installation	High
16	III	C	255	359	All	Customer Meter Installations - Operating Pressure	Other
16	III	C	255	361	(a),(b),(c),(d)	Service Lines - Installation	Other
16	III	C	255	361	(e),(f),(g),(h),(i)	Service Lines - Installation	High
16	III	C	255	363	All	Service Lines - Valve Requirements	Other
16	III	C	255	365	(a),(c)	Service Lines - Location of Valves	Other
16	III	C	255	365	(b)	Service Lines - Location of Valves	High
16	III	C	255	367	All	Service Lines - General Requirements for Connections	Other
16	III	C	255	369	All	Service Lines - Connections to Cast Iron or Ductile Iron Mains	Other
16	III	C	255	371	All	Service Lines - Steel	Other
16	III	C	255	373	All	Service Lines - Cast Iron and Ductile Iron	Other
16	III	C	255	375	All	Service Lines - Plastic	Other
16	III	C	255	377	All	Service Lines - Copper	Other
16	III	C	255	379	All	New Service Lines not in Use	Other
16	III	C	255	381	All	Service Lines - Excess Flow Valve Performance Standards	Other
16	III	C	255	455	(a)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	Other
16	III	C	255	455	(d),(e)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	High
16	III	C	255	457	All	External Corrosion Control - Buried or Submerged Pipelines Installed before July 31, 1971	High
16	III	C	255	459	All	External Corrosion Control - Examination of Buried Pipeline when Exposed	Other
16	III	C	255	461	(a),(b),(d),(e),(f),(g)	External Corrosion Control - Protective Coating	Other

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	461	(c)	External Corrosion Control - Protective Coating	High
16	III	C	255	463	All	External Corrosion Control - Cathodic Protection	High
16	III	C	255	465	(a),(e)	External Corrosion Control - Monitoring	High
16	III	C	255	465	(b),(c),(d),(f)	External Corrosion Control - Monitoring	Other
16	III	C	255	467	All	External Corrosion Control - Electrical Isolation	Other
16	III	C	255	469	All	External Corrosion Control - Test Stations	Other
16	III	C	255	471	All	External Corrosion Control - Test Leads	Other
16	III	C	255	473	All	External Corrosion Control - Interference Currents	Other
16	III	C	255	475	All	Internal Corrosion Control - General	Other
16	III	C	255	476	(a),(c)	Internal Corrosion Control - Design and Construction of Transmission Line	High
16	III	C	255	476	(d)	Internal Corrosion Control - Design and Construction of Transmission Line	Other
16	III	C	255	479	All	Atmospheric Corrosion Control - General	Other
16	III	C	255	481	All	Atmospheric Corrosion Control - Monitoring	Other
16	III	C	255	483	All	Remedial Measures - General	High
16	III	C	255	485	(a),(b)	Remedial Measures - Transmission Lines	High
16	III	C	255	485	(c)	Remedial Measures - Transmission Lines	Other
16	III	C	255	487	All	Remedial Measures - Distribution Lines other than Cast Iron or Ductile Iron Lines	Other
16	III	C	255	489	All	Remedial Measures - Cast Iron and Ductile Iron Pipelines	Other
16	III	C	255	490	All	Direct Assessment	Other
16	III	C	255	491	All	Corrosion Control Records	Other
16	III	C	255	493	All	In-Line Insepction of Pipelines	High
16	III	C	255	503	All	Test Requirements - General	Other
16	III	C	255	505	(a),(b),(c),(d)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	505	(e),(h),(i)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	Other
16	III	C	255	506	All	Transmission Lines - Spike Hydrostatic Pressure Test	High
16	III	C	255	507	All	Test Requirements for Pipelines to Operate at less than 125 PSIG (862 kPa)	Other
16	III	C	255	511	All	Test Requirements for Service Lines	Other
16	III	C	255	515	All	Environmental Protection and Safety Requirements	Other
16	III	C	255	517	All	Test Requirements - Records	Other
16	III	C	255	552	All	Upgrading / Conversion - Notification Requirements	Other
16	III	C	255	553	(a),(b),(c),(f)	Upgrading / Conversion - General Requirements	High
16	III	C	255	553	(d),(e)	Upgrading / Conversion - General Requirements	Other
16	III	C	255	555	All	Upgrading to a Pressure of 125 PSIG (862 kPa) or More in Steel Pipelines	High
16	III	C	255	557	All	Upgrading to a Pressure Less than 125 PSIG (862 kPa)	High
16	III	C	255	603	All	Operations - General Provisions	High
16	III	C	255	604	All	Operator Qualification	High
16	III	C	255	605	All	Essentials of Operating and Maintenance Plan	High
16	III	C	255	607	All	Verification of Pipeline Materials and Attributes - Onshore Steel Transmission Pipelines	High
16	III	C	255	609	All	Change in Class Location - Required Study	High
16	III	C	255	611	(a),(d)	Change in Class Location - Confirmation or Revision of Maximum Allowable Operating Pressure	Other
16	III	C	255	613	All	Continuing Surveillance	Other
16	III	C	255	614	All	Damage Prevention Program	High

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	615	All	Emergency Plans	High
16	III	C	255	616	All	Customer Education and Information Program	High
16	III	C	255	619	All	Maximum Allowable Operating Pressure - Steel or Plastic Pipelines	High
16	III	C	255	621	All	Maximum Allowable Operating Pressure - High Pressure Distribution Systems	High
16	III	C	255	623	All	Maximum and Minimum Allowable Operating Pressure - Low Pressure Distribution Systems	High
16	III	C	255	624	All	Maximum Allowable Operating Pressure Reconfirmation - Onshore Steel Transmission Pipelines	High
16	III	C	255	625	(a),(b)	Odorization of Gas	High
16	III	C	255	625	(e),(f)	Odorization of Gas	Other
16	III	C	255	627	All	Tapping Pipelines Under Pressure	High
16	III	C	255	629	All	Purging of Pipelines	High
16	III	C	255	631	All	Control Room Management	High
16	III	C	255	632	All	Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation - Onshore Steel Transmission Pipelines	High
16	III	C	255	705	All	Transmission Lines - Patrolling	High
16	III	C	255	706	All	Transmission Lines - Leakage Surveys	High
16	III	C	255	707	(a),(c),(d),(e)	Line Markers for Mains and Transmission Lines	Other
16	III	C	255	709	All	Transmission Lines - Record Keeping	Other
16	III	C	255	710	(b),(c),(d),(e),(f),(g)	Transmission Lines - Assessments Outside of High Consequence Areas	High
16	III	C	255	711	All	Transmission Lines - General Requirements for Repair Procedures	High
16	III	C	255	712	(a),(b),(d),(e),(f),(g)	Analysis of Predicated Failure Pressure	High
16	III	C	255	713	All	Transmission Lines - Permanent Field Repair of Imperfections and Damages	High
16	III	C	255	715	All	Transmission Lines - Permanent Field Repair of Welds	High
16	III	C	255	717	All	Transmission Lines - Permanent Field Repairs of Leaks	High
16	III	C	255	719	All	Transmission Lines - Testing of Repairs	High
16	III	C	255	721	(b)	Distribution Systems - Patrolling	Other
16	III	C	255	723	All	Distribution Systems -Leakage Surveys and Procedures	High
16	III	C	255	725	All	Test Requirements for Reinstating Service Lines	Other
16	III	C	255	726	All	Inactive Service Lines	Other
16	III	C	255	727	(b),(c),(d),(e),(f),(g)	Abandonment or Inactivation of Facilities	Other
16	III	C	255	729	All	Compressor Stations - Procedures for Gas Compressor Units	High
16	III	C	255	731	All	Compressor Stations - Inspection and Testing of Relief Devices	High
16	III	C	255	732	All	Compressor Stations - Additional Inspections	High
16	III	C	255	735	All	Compressor Stations - Storage of Combustible Materials	Other
16	III	C	255	736	All	Compressor Stations - Gas Detection	High
16	III	C	255	739	(a),(b)	Pressure Limiting and Regulating Stations - Inspection and Testing	High
16	III	C	255	739	(c),(d),(e),(f)	Pressure Limiting and Regulating Stations - Inspection and Testing	Other
16	III	C	255	740	(b)	Pressure regulating, limiting, and overpressure protection - Individual service lines directly connected to gathering or transmission pipelines	High
16	III	C	255	741	All	Pressure Limiting and Regulating Stations - Telemetering or Recording Gauges	Other

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	743	(a),(b)	Pressure and Limiting and Regulating Stations - Testing of Relief Devices	High
16	III	C	255	743	(c)	Regulator Station MAOP	Other
16	III	C	255	744	All	Service Regulators and Vents - Inspection	Other
16	III	C	255	745	All	Transmission Line Valves	High
16	III	C	255	747	All	Valve Maintenance - Distribution Systems	Other
16	III	C	255	748	All	Valve Maintenance - Service Line Valves	Other
16	III	C	255	749	All	Vault Maintenance	Other
16	III	C	255	750	All	Launcher and Receiver Safety	High
16	III	C	255	751	All	Prevention of Accidental Ignition	High
16	III	C	255	753	All	Caulked Bell and Spigot Joints	Other
16	III	C	255	755	All	Protecting Cast Iron Pipelines	High
16	III	C	255	756	All	Replacement of Exposed or Undermined Cast Iron Piping	High
16	III	C	255	757	All	Replacement of Cast Iron Mains Paralleling Excavations	High
16	III	C	255	801	All	Reports of accidents	Other
16	III	C	255	803	All	Emergency Lists of Operator Personnel	Other
16	III	C	255	805	(a),(b),(e),(g),(h)	Leaks - General	Other
16	III	C	255	807	(a),(b),(c)	Leaks - Records	Other
16	III	C	255	807	(d)	Leaks - Records	High
16	III	C	255	809	All	Leaks - Instrument Sensitivity Verification	High
16	III	C	255	811	(b),(c),(d),(e)	Leaks - Type 1 Classification	High
16	III	C	255	813	(b),(c),(d)	Leaks - Type 2A Classification	High
16	III	C	255	815	(b),(c),(d)	Leaks - Type 2 Classification	High
16	III	C	255	817	All	Leaks - Type 3 Classification	Other
16	III	C	255	819	(a)	Leaks - Follow-Up Inspection	High
16	III	C	255	821	All	Leaks - Nonreportable Reading	High
16	III	C	255	823	(a),(b)	Interruptions of Service	Other
16	III	C	255	825	All	Logging and Analysis of Gas Emergency Reports	Other
16	III	C	255	829	All	Annual Report	Other
16	III	C	255	831	All	Reporting Safety-Related Conditions	Other
16	III	C	255	905	All	High Consequence Areas	High
16	III	C	255	907	All	General (IMP)	Other
16	III	C	255	909	All	Changes to an Integrity Management Program (IMP)	Other
16	III	C	255	911	All	Required Elements (IMP)	High
16	III	C	255	915	All	Knowledge and Training (IMP)	High
16	III	C	255	917	All	Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	High
16	III	C	255	919	All	Baseline Assessment Plan (IMP)	High
16	III	C	255	921	All	Conducting a Baseline Assessment (IMP)	High
16	III	C	255	923	All	Direct Assessment (IMP)	High
16	III	C	255	925	All	External Corrosion Direct Assessment (ECDA)(IMP)	High
16	III	C	255	927	All	Internal Corrosion Direct Assessment (ICDA)(IMP)	High
16	III	C	255	931	All	Confirmatory Direct Assessment (CDA)(IMP)	High
16	III	C	255	933	All	Addressing Integrity Issues (IMP)	High
16	III	C	255	935	All	Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	High
16	III	C	255	937	All	Continual Process of Evaluation and Assessment (IMP)	High
16	III	C	255	939	All	Reassessment Intervals (IMP)	High
16	III	C	255	941	All	Low Stress Reassessment (IMP)	Other
16	III	C	255	945	All	Measuring Program Effectiveness (IMP)	Other
16	III	C	255	947	All	Records (IMP)	Other

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	1003	All	General Requirements of a GDPIM Plan	High
16	III	C	255	1005	All	Implementation Requirements of a GDPIM Plan	High
16	III	C	255	1007	All	Required Elements of a GDPIM Plan	High
16	III	C	255	1009	All	Required Report when Compression Couplings Fail	High
16	III	C	255	1011	All	Records an Operator Must Keep (GDPIM)	Other
16	III	C	255	1015	All	GDPIM Plan Requirements for a Master Meter or a Small Liquefied Petroleum Gas (LPG) Operator	High
16	III	C	261	15	All	Operation and Maintenance Plan	High
16	III	C	261	17	(a),(c)	Leakage Survey	High
16	III	C	261	19	All	High Pressure Piping	Other
16	III	C	261	21	All	Carbon Monoxide Prevention	High
16	III	C	261	51	All	Warning Tag Procedures	High
16	III	C	261	53	All	HEFPA Liaison	High
16	III	C	261	55	All	Warning Tag Inspection	High
16	III	C	261	57	All	Warning Tag - Class A condition	High
16	III	C	261	59	All	Warning Tag - Class B condition	High
16	III	C	261	61	All	Warning Tag - Class C Condition	Other
16	III	C	261	63	All	Warning Tag - Action and Follow-Up	Other
16	III	C	261	65	All	Warning Tag Records	Other
49	I	D	193	2011	All	Reporting	Other
49	I	D	193	2017	All	Plans and Procedures	High
49	I	D	193	2019	All	Mobile and Temporary LNG Facilities	High
49	I	D	193	2057	All	Thermal Radiation Protection	High
49	I	D	193	2059	All	Flammable Vapor-Gas Dispersion Protection	High
49	I	D	193	2067	All	Wind Forces	High
49	I	D	193	2101	All	Design - Scope	High
49	I	D	193	2119	All	Design - Records	High
49	I	D	193	2155	All	Structural Requirements	High
49	I	D	193	2161	All	Design - Dikes	High
49	I	D	193	2167	All	Covered Systems	High
49	I	D	193	2173	All	Water Removal	High
49	I	D	193	2181	All	Impoundment Design and Capacity	High
49	I	D	193	2187	All	Nonmetallic Membrane Liner	High
49	I	D	193	2301	All	Construction - Scope	High
49	I	D	193	2303	All	Construction Acceptance	High
49	I	D	193	2304	All	Corrosion Control Overview	High
49	I	D	193	2321	All	Nondestructive Tests	High
49	I	D	193	2401	All	Equipment - Scope	High
49	I	D	193	2441	All	Equipment - Control Center	High
49	I	D	193	2445	All	Sources of Power	High
49	I	D	193	2501	All	Operations - Scope	High
49	I	D	193	2503	All	Operating Procedures	High
49	I	D	193	2505	All	Operations - Cooldown	High
49	I	D	193	2507	All	Monitoring Operations	High
49	I	D	193	2509	All	Emergency Procedures	High
49	I	D	193	2511	All	Personnel Safety	High
49	I	D	193	2513	All	Transfer Procedures	High
49	I	D	193	2515	All	Investigations of Failures	High
49	I	D	193	2517	All	Purging	High
49	I	D	193	2519	All	Communication Systems	High

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
49	I	D	193	2521	All	Operating Records	Other
49	I	D	193	2603	All	Maintenance - General	High
49	I	D	193	2605	All	Maintenance Procedures	High
49	I	D	193	2607	All	Foreign Material	Other
49	I	D	193	2609	All	Support Systems	High
49	I	D	193	2611	All	Fire Protection	High
49	I	D	193	2613	All	Auxiliary Power Sources	High
49	I	D	193	2615	All	Isolating and Purging	High
49	I	D	193	2617	All	Maintenance - Repairs	High
49	I	D	193	2619	All	Control Systems	High
49	I	D	193	2621	All	Testing Transfer Hoses	High
49	I	D	193	2623	All	Inspecting LNG Storage Tanks	High
49	I	D	193	2625	All	Corrosion Protection	High
49	I	D	193	2627	All	Atmospheric Corrosion Control	Other
49	I	D	193	2629	All	External Corrosion Control - Buried or Submerged Components	Other
49	I	D	193	2631	All	Internal Corrosion Control	Other
49	I	D	193	2633	All	Interference Currents	Other
49	I	D	193	2635	All	Monitoring Corrosion Control	High
49	I	D	193	2637	All	Remedial Measures	High
49	I	D	193	2639	All	Maintenance Records	Other
49	I	D	193	2703	All	Design and Fabrication	Other
49	I	D	193	2705	All	Construction, Installation, Inspection, and Testing	High
49	I	D	193	2707	All	Operations and Maintenance	High
49	I	D	193	2709	All	Security	High
49	I	D	193	2711	All	Personnel Health	Other
49	I	D	193	2713	All	Training - Operations and Maintenance	High
49	I	D	193	2715	All	Training - Security	High
49	I	D	193	2717	All	Training - Fire Protection	High
49	I	D	193	2719	All	Training - Records	Other
49	I	D	193	2801	All	Fire Protection	High
49	I	D	193	2903	All	Security Procedures	High
49	I	D	193	2905	All	Protective Enclosures	High
49	I	D	193	2907	All	Protective Enclosure Construction	High
49	I	D	193	2909	All	Security Communications	High
49	I	D	193	2911	All	Security Lighting	High
49	I	D	193	2913	All	Security Monitoring	High
49	I	D	193	2915	All	Alternative Power Sources	High
49	I	D	193	2917	All	Warning Signs	Other

Appendix V
Central Hudson Gas and Electric Corporation
Cases 24-E-0461 and 24-G-0462

Customer Service Performance Indicators - Central Hudson

Calendar Year 2026		Calendar Year 2027		Calendar Year 2028	
PSC Complaint Rate	NRA	PSC Complaint Rate	NRA	PSC Complaint Rate	NRA
≤ 1.0	0 Basis Points	≤ 1.0	0 Basis Points	≤ 1.0	0 Basis Points
> 1.0	5 Basis Points	> 1.0	5 Basis Points	> 1.0	5 Basis Points
≥ 1.1	10 Basis Points	≥ 1.1	10 Basis Points	≥ 1.1	10 Basis Points
≥ 1.2	15 Basis Points	≥ 1.2	15 Basis Points	≥ 1.2	15 Basis Points
Customer Satisfaction Survey	NRA	Customer Satisfaction Survey	NRA	Customer Satisfaction Survey	NRA
≥ 89.0%	0 Basis Points	≥ 89.0%	0 Basis Points	≥ 89.0%	0 Basis Points
< 89.0%	5 Basis Points	< 89.0%	5 Basis Points	< 89.0%	5 Basis Points
≤ 87.1%	10 Basis Points	≤ 87.1%	10 Basis Points	≤ 87.1%	10 Basis Points
≤ 85.3%	15 Basis Points	≤ 85.3%	15 Basis Points	≤ 85.3%	15 Basis Points
Call Answer Rate	NRA	Call Answer Rate	NRA	Call Answer Rate	NRA
≥ 67.0%	0 Basis Points	≥ 67.0%	0 Basis Points	≥ 67.0%	0 Basis Points
< 67.0%	4 Basis Points	< 67.0%	5 Basis Points	< 67.0%	5 Basis Points
≤ 61.4%	8 Basis Points	≤ 61.4%	10 Basis Points	≤ 61.4%	10 Basis Points
≤ 55.8%	12 Basis Points	≤ 55.8%	13 Basis Points	≤ 55.8%	15 Basis Points
Total At Risk:	42 Basis Points	Total At Risk:	43 Basis Points	Total At Risk:	45 Basis Points

Appendix W
Central Hudson Gas and Electric Corporation
Cases 24-E-0461 and 24-G-0462

OUTREACH AND EDUCATION PLAN 2025

Appendix X
Sheet 1 of 17
Central Hudson Gas & Electric Corporation
Cases 24-E-0461 and 24-G-0462

Earnings Adjustment Mechanisms

The following table lists the Earnings Adjustment Mechanisms ("EAM") award opportunity in dollars for each EAM during calendar years 2026-2028.

Annual Dollar Award (1) (2)	Achievement Level	2026	2027	2028
System Efficiency EAMs and Scorecard Metrics				
DER Utilization – Photovoltaic (PV)	Min	$270,200	$285,400	$291,600
	Mid	$540,400	$570,800	$583,200
	Max	$1,080,800	$1,141,600	$1,166,400
DER Utilization – Battery Energy Storage Systems (BESS)	Min	$270,200	$285,400	$291,600
	Mid	$540,400	$570,800	$583,200
	Max	$1,080,800	$1,141,600	$1,166,400
Electric Load Management	Min	$303,975	$321,075	$328,050
	Mid	$439,075	$463,775	$473,850
	Max	$675,500	$713,500	$729,000
Residential Managed Charging	Min	$270,200	$285,400	$291,600
	Mid	$405,300	$428,100	$437,400
	Max	$675,500	$713,500	$729,000
Load Factor	N/A	N/A	N/A	N/A
Residential Energy Intensity	N/A	N/A	N/A	N/A
Commercial Energy Intensity	N/A	N/A	N/A	N/A
Gas Peak Reduction	N/A	N/A	N/A	N/A
Beneficial Electrification EAMs				
EV Adoption EAM	Min	$337,750	$356,750	$364,500
	Mid	$540,400	$570,800	$583,200
	Max	$1,080,800	$1,141,600	$1,166,400
	Min	**$1,452,325**	**$1,534,025**	**$1,567,350**
	Mid	**$2,465,575**	**$2,604,275**	**$2,660,850**
Total Max Electric	Max	**$4,593,400**	**$4,851,800**	**$4,957,200**
Total Gas	N/A	**N/A**	**N/A**	**N/A**

(1) Electric basis point values are $130,600, $139,600, and $145,600 in RY1, RY2, and RY3 respectively.
(2) Electric basis point values are $135,100, $142,700, and $145,800 in calendar years 2026, 2027, and 2028 respectively.

These EAMs will be in effect during calendar years 2026 through 2028 unless terminated by the Commission in a generic proceeding. The EAMs provided for in this Proposal shall not continue after 2028 without Commission action. This does not preclude parties from proposing to new or continued EAMs in subsequent rate proceedings. For each EAM with an earnings component, performance between minimum and midpoint targets, or midpoint and maximum targets, will result in the Company earning a linearly prorated share of the EAM.

1. **DER PV Utilization**
   a. Description

   The Distributed Energy Resource ("DER") Photovoltaic ("PV") Utilization EAM metric incentivizes Central Hudson to work with third parties to expand the use of DER PV resources in the Company's service territory.

   b. Metric

   This metric will measure the sum of the megawatts ("MW") Alternating Current ("AC") nameplate of all incremental solar interconnections less than or equal to 5 MW AC in Central Hudson's service territory, including projects participating in the Statewide Solar-For-All or Renewable Energy Access and Community Help ("REACH") programs.

   c. Measurement

   The DER PV Utilization metric will be based on the total MW (AC) from PV installed during the calendar year, excluding any Company owned PV systems.

   d. Achievement

   To determine achievement, Annual DER PV Utilization will be compared against the target levels as follows:

	Target Level	**2026**	**2027**	**2028**
DER PV Utilization EAM Targets (MW)	**Minimum**	31.71	34.88	38.37
	Midpoint	36.03	39.63	43.60
	Maximum	43.24	47.56	52.32

2. **DER BESS Utilization**
   a. Description

   The DER Battery Energy Storage Systems ("BESS") Utilization EAM metric incentivizes Central Hudson to work with third parties to expand the use of DER BESS resources in the Company's service territory.

   b. Metric

   This metric will measure the sum of the MW AC nameplate of all incremental BESS interconnections less than or equal to 5 MW AC in Central Hudson's service territory, including projects participating in the Statewide Solar-For-All or REACH programs.

   c. Measurement

   In the February 14, 2025 Order Approving Implementation Plan with Modifications, issued in Case 18-E-0130, the Commission established a requirement that residential energy storage projects that receive an incentive must participate in the dynamic load management program for the project's location if one exists. While no program currently exists in Central Hudson's territory, the Commission is considering proposals from the utilities for the inclusion of energy storage in their direct load control programs in Case 14-E-0423.

It is anticipated that these systems will be a very small part of the overall Energy Storage portfolio, and a very small part of the total Dynamic Load Management ("DLM") Program portfolio, and given the scale of the Energy Storage and DLM Program portfolios that residential storage will be part of, the potential impact of Energy Storage getting counted toward both metrics would be de minimus. However, to ensure double counting does not occur, the Company is not allowed to count a single Residential Storage project for more than one EAM. The Company shall track which projects are being counted for each EAM.

The DER BESS Utilization metric will be based on the total MW (AC) of battery storage installed during the calendar year, excluding any Company owned battery storage systems.

d. Achievement

To determine achievement, Annual DER BESS Utilization will be compared against the target levels as follows:

The target reflects baselines that include all interconnected BESS in 2024:

BESS Target Year End, Incremental	Target Level	2026	2027	2028
	Minimum	4.70	5.97	7.58
	Midpoint	5.34	6.78	8.61
	Maximum	6.41	8.14	10.33

Targets are calculated as follows:

Growth Rate Calculation:

Step	Description	Quantity	Item	Calculation	Source
1	New York State 2030 storage goal (MW)	6,000.00	A		
	Central Hudson share of storage goal (MW)	200.82	B	A * B.3	
	2019 Central Hudson Peak Load (MW) [3]	1,083.00	B.1		[3] 2019 NYCA coincident peak weather normalized from NYISO, slide 7
	2019 NYCA Peak Load (MW) [3]	32,357.00	B.2		**[3] 2019 NYCA coincident** peak weather normalized from NYISO, slide 7
	Central Hudson % share of Total NYCA Peak Load	3.3%	B.3	B.3 / B.2	
	Central Hudson SIR portion (MW)	**52.29**	C	B * C.4	
	Commercial Retail Projects (MW) [4]	320.00	C.1		**[4] NYSERDA Third Annual** State of Storage report, p. 3
	NYSERDA Bridge incentive (MW) [4]	879.00	C.2		**[4] NYSERDA Third Annual** State of Storage report, p. 3
	2018 Storage Order Utility Bulk Projects [5]	350.00	C.3		**[5] 18-E-0130 Order Establishing** Energy Storage Goal and Deployment Policy (issued December 13, 2018), p. 55
	% share of 2018 Storage Order allocated to projects 5 MW or less	0.26	C.4	C.1 / (C.2 + C.3)	-
2	SIR storage installed in Central Hudson territory through 2024 (actual)	11.98	D		Central Hudson Interconnection data
	7 yr Cumulative Exponential Growth Factor to reach SIR share in 2030	0.21	E.1	ln(C / E) / 7	7 year exponential growth rate based on Exponential growth formula, e.g. X1 = X0 * e^(r * y), where r = exponential growth factor y = years (e.g. 7 years from 2023 to 2030) X0 = BESS in year 0 (e.g. 2023) X1 = BESS in future year (e.g. 2030)

Baseline Calculation:

Cumulative Annual Baseline = (X0)*e^(r*(y-2024)) – Calculate for y=2025, 2026, 2027, 2028

Annual Incremental Baseline = Current year's cumulative annual baseline – Prior year's cumulative annual baseline

Targets:

Min = Annual Incremental Baseline x 1.1

Mid = Annual Incremental Baseline x 1.25

Max = Annual Incremental Baseline x 1.5

3. Electric Load Management EAM

a. Description

The Electric Load Management ("ELM") EAM encourages the Company to achieve greater growth in its load management programs by increasing the total MW of load reduction participating in the programs. This EAM promotes grid flexibility by developing a larger and more reliable portfolio of load management resources that can be called on to reduce peak demand and during system contingencies. The metric will measure the Operationally Available MWs achieved through all of the Company's load management programs[1] such as the Commercial System Relief Program ("CSRP") and the Term- and Auto-Dynamic Load Management ("DLM") programs, as well as the NYISO Special Case Resource ("SCR") program within the Company's service territory.[2] Operationally Available MWs will be calculated using the enrolled MWs for the Company's load management programs multiplied by performance factor not to exceed 100% for measures where performance factor is applicable. NYISO SCR MWs will be calculated using obligated Installed Capacity MW multiplied by the percent response of obligated MW not to exceed 100%.

b. Metric

The ELM EAM is the sum total operationally available MW from the Company's load management programs and the portion of the NYISO SCR program within the Company's service territory in any given calendar year:

CY_x MW Reduction

[1] Excludes Non-Wires Alternatives

[2] The NYISO SCR Program data in the Company's service territory remains pending determination of the relevant NYISO data. Until such time NYISO SCR Program data in the Company's service territory is available, the ELM EAM will consist of the Operationally Available MWs achieved through all of the Company's load management programs.

Where,

X	1, 2 and 3 for Calendar year 1, Calendar year 2, or Calendar year 3, respectively.
CY_X MW Reduction	The total operationally available MW in calendar year x from the total of the Company's load management programs, calculated using the methodology that the Company has employed when reporting 2016 – 2024 load management program data in its Annual Report and the NYISO SCR program.

c. Measurement

The Company will use data calculated using the methodology that the Company has employed when reporting 2016 – 2024 load management program data in the Company's Annual Load Management Program report to measure operationally available MW from Company load management programs and the NYISO SCR data provided in the NYISO Annual Report on Demand Response Programs.

d. Targets

Targets for each calendar year for the Company's load management programs are determined based on exceeding the highest-achieved, historic program capacity from the years 2016 through 2024, and are updated each calendar year based on the prior year's actual performance. Targets will be set at improvements of 10%, 30% and 50% above the baseline for the minimum, midpoint, and maximum targets, respectively. The following table outlines the Load Management EAM targets for CY 1, 2 and 3 respectively, expressed in annual incremental MW above the baseline.

	Performance Level	**CY1 (2026)**	**CY2 (2027)**	**CY3 (2028)**
Incremental Program Capacity (MW)	Baseline	9.402	Determined formulaically based on prior years actual performance	
	Min (+10%)	10.342		
	Mid (+30%)	12.222		
	Max (+50%)	14.103		

Note: The baseline for the year 2026 (CY1) of 9.402 MW is for illustration purposes only. The value was derived from the portfolio's highest capacity performance in year 2019 of 8.547 MW with an increase of 10%. The 2026 baseline will consider 2024 and 2025 operationally available MW for highest capacity achieved.

Where,

X	1, 2 and 3 for Calendar year 1, Calendar year 2, or Calendar year 3, respectively.
RY_X Baseline	The incremental MW load reduction baseline in Calendar year x calculated as follows: Highest Ever Operationally Available Achieved MW Load Reduction × (1 + 10%)

Targets for each calendar year for the NYISO SCR program will be set at improvements of 0%, 10%, and 20% above the prior year's MW reduction. The following table outlines the Load Management EAM targets for the NYISO SCR program for CY 1, 2 and 3 respectively, expressed in annual incremental MW above the prior year's MW reduction.

	Performance Level	**CY_1 (2026)**	**CY_2 (2027)**	**CY_3 (2028)**
Incremental NYISO SCR Program Capacity (MW)	Min (+0%)	Determined formulaically based on prior years actual performance		
	Mid (+10%)			
	Max (+20%)			

e. Achievement

Achievement will be determined by comparing the total of the Company's Load Management Program and NYISO SCR Program performance (MW) for a specific year to the established Incremental Load Management capacity targets set for the same year. For performance between minimum and midpoint, or midpoint and maximum, the Company would earn a linearly prorated share.

4. Residential Managed Charging EAM

a. Description

The Residential Managed Charging ("RMC") component of the EAM encourages Company efforts that will (1) increase electric vehicle ("EV") enrollment in the EV ChargeSmart managed charging program,[3] (2) encourage program participants to avoid EV charging during system peak hours (2PM – 7PM) and (3) reduce program

[3] ChargeSmart is a passive managed charging program that incentivizes drivers to avoid on-peak EV charging and increase off-peak charging.

participants' EV charging demand coincident with system peak hours. The RMC EAM measures enrollment, and the peak coincident demand of all customers enrolled in ChargeSmart. The RMC EAM measures enrollment through the end of the calendar year. The RMC EAM measures peak coincident demand of all customers enrolled in ChargeSmart during the summer period defined as Pactual (see Section b), and then scales Pactual up to the full year to align the timing of the variables. The mechanism for scaling up Pactual is described in section c.

b. Metric

The RMC metric measures avoided peak charging in kilowatts (kW) per EV on the road in the Company's service territory.

For CY1, Avoided Peak Charging per EV (kW) = (CY1 Pmaxderated – CY1 Pactual) / CY1 EVs on the road YE

Where,

Pmaxderated	Pmaxderated is the sum of the maximum possible demand of electric vehicles enrolled in ChargeSmart through the end of CY1, based on manufacturer specifications for the maximum charging rate of the vehicles, multiplied by 5.5%, the ratio of a typical 2023 Level 2 charger capacity (9.3 kW) to the 2023 average Pmax per vehicle enrolled (170 kW). The rationale for derating Pmax is described below in this section.
PactualYE	PactualYE is Pactual scaled to a year-end value so that appropriate time alignment with year-end enrollment occurs. The scaling uses a ratio of Pmax during the month of Pactual in the summer to Pmax at year-end, calculated as follows: PactualYE = Pactual × (PmaxderatedYE / Pmaxderated)
Pactual	The highest aggregate observed coincident charging demand (kW) of enrolled EVs in the program during the system peak period (2pm-7pm) between June and September.
Pmax	Pmax is the sum of the maximum possible demand of electric vehicles enrolled in ChargeSmart at the end of the month in which Pactual occurs, based on manufacturer specifications for the maximum charging rate of the vehicles. Pmaxderated is Pmax multiplied by 5.5%.
EVs on the roadYE	Total number of light-duty EVs in the Company's service territory at the end of CY1.

For CY2 and CY3, Avoided Peak Charging per EV (kW) = (CYxPmaxderated – CYxPactual) / CYxEVs on the road

Where,

x	Is equal to 2 and 3 for CY2 and CY3 respectively.
Pmaxderated	Pmax is the sum of the maximum possible demand of electric vehicles enrolled in ChargeSmart at the end of the month in which Pactual occurs, based on manufacturer specifications for the maximum charging rate of the vehicles. Pmaxderated is Pmax multiplied by 5.5%.
Pactual	The highest aggregate observed coincident charging demand (kW) of enrolled EVs in the program during the system peak period (2pm-7pm) between June and September.
EVs on the road	Total number of light-duty EVs in the Company's service territory at the end of CYx at the end of the month in which Pactual occurs.

c. Rationale for Derating Pmax

Pmax is derated so that the metric is sensitive to both Pmax, which is representative of total enrollment, and Pactual, which is representative of the performance of enrolled customers. Since the ChargeSmart program's inception in November of 2023, Central Hudson has offered incentives to drivers to charge their vehicles overnight rather than during peak hours. The program has been successful in encouraging participants to avoid charging during peak hours, and as a result, the baseline data for Pactual is very low compared to Pmax. This makes the metric relatively insensitive to Pactual: a 5.5% change in Pactual yields approximately a 0.01% change in the value of the metric, while a 5.5% change in enrollment yields a 5.5% change in the metric. The EAM is intended to encourage the Company to maintain this low Pactual for existing participants and influence new participants' behavior to similarly low levels. By derating Pmax, Pactual and Pmax are more closely aligned in value to one another, which increases the sensitivity of the metric to changes in Pactual. After derating Pmax, a 5.5% change in Pactual yields approximately a 0.5% change in the metric while the sensitivity to enrollment remains the same. Keeping Pactual low – i.e., consistent with historical levels – is one of the goals of the EAM.

The derating of Pmax is based on the average capacity of an EV compared to the typical capacity of a level 2 charger. The Company believes this ratio is appropriate during the 2026-2028 rate period given current market conditions in Central Hudson's service territory regarding EVs and available charging capacity. The derating factor will be revisited in the future and adjusted based on future market conditions (particularly the relative penetration of fast chargers and level 2 chargers).

While this metric could have been expressed without dividing by the total number of EVs on the road, that element is included to encourage the Company to keep pace with market growth during the rate plan. That is, the Company will need to increase its efforts to maintain the low ratio between the derated Pmax and Pactual as more EVs are purchased and operated within its service territory.

d. Measurement

The Company will measure Pactual, the maximum aggregate coincident vehicle charging demand during the system peak window, through data from the ChargeSmart program aggregated by its software partner.4 Pactual will be based on the single data measurement interval during the summer period (June through September) during system peak hours (2pm-7pm) when charging load aggregated across all program participants is highest. The Company will use vehicle specifications to determine Pmax.

The Company tracks the number of electric vehicles on the road in its service territory using Atlas' EValuateNY, a NYSERDA funded tool that uses vehicle registration data from the New York State Department of Motor Vehicles.[5]

e. Targets

Targets ("CYx RMC Target") for performance will be set as a percent improvement in the value of the RMC EAM metric relative to the historical baseline. The percent improvements for the minimum, midpoint, and maximum in each Rate Year are shown in Table 1 below.

Table 1.

	Level	CY1 (2026)	CY2 (2027)	CY3 (2028)
RMC Targets (Percent Improvement in Avoided Peak Charging per EV on the road)	Min	5%	5%	5%
	Mid	10%	10%	10%
	Max	17%	17%	17%

[4] ChargeSmart's software partner is Virtual Peaker.
[5] Atlas EValuateNY: https://atlaspolicy.com/evaluateny/

The baseline is calculated as follows:

Baseline Avoided Peak Charging per EV (kW)

$$= \frac{\text{CYxBaseline Pmaxderated} - \text{CYxBaseline Pactual}}{\text{CYxBaseline EVs on the road}}$$

Where,

x	Is equal to 1, 2 and 3 for CY1, CY2, and CY3, respectively.
Baseline Pmaxderated	The product of EVs on the road, enrollment percent, average maximum charging capacity per vehicle, and 5.5% for derating, calculated as follows: CYxBaseline EVs on the road × Baseline Enrollment % × Baseline Average Vehicle Pmax × 5.5%
Baseline Enrollment %	For Calendar Year 1, the baseline will be developed using the prior year's enrollment rate plus the average historical increase in enrollment percent year over year.
Baseline Average Vehicle Pmax	Set to the average Pmax per vehicle forecasted based on 2023-2025 historical growth data.
Baseline Pactual	The product of Baseline Pmaxderated and the 2023-2025 historical average ratio of Pactual to Pmax, is calculated as follows: Baseline Pmaxderated × Historical Average ratio of Pactual to Pmax
Baseline EVs on the road	Total number of light-duty EVs forecasted to be in the Company's service territory from the Company Distributed System Implementation Plan.6 For CY1, the baseline is the forecast year-end value. For CY2 and CY3, the baseline is the forecast value at the end of the month in which Pactual occurs.

The Baseline Enrollment % methodology described above will encourage the Company to continue to grow enrollment faster than the growth of the underlying EV market; a constant enrollment % would keep pace with the market, so a growing

[6] Case 16-M-0411: Central Hudson Distributed System Implementation Plan (filed June 30, 2023)

enrollment rate outpaces the market. If the Company were to underperform and fall behind, the Company would need to grow enrollment at an even faster rate in the next year than if it were to meet targets.

f. Achievement

The Company will report achievement using the following steps:

Step 1: RMC EAM achievement in a given rate year (CYx Percent Improvement in Avoided Peak Charging Per EV (kW)), will be calculated as described in Section 2 above.

Step 2: The Company will calculate the earned reward in a given rate year corresponding to its CYx Percent Improvement in the value of the RMC EAM metric described in section 5 above.

g. Reporting

The reporting for the Managed Charging collaborative will be completed in the same period as the remaining Company EAMs.

5. <u>Load Factor Scorecard Metric</u>

a. Description

This metric tracks the deployment of energy storage and other DERs. The Company will track changes to load factor over time and monitor the potential impacts to load factor that results from the utilization of DER's throughout the system. This metric is a tracking-only scorecard metric.

b. Metric

The Company will track and report the absolute load factor (non-weather normalized) at the substation level. The data can be weather normalized later if required by DPS Staff.

c. Measurement

The Company will set up an annual process to prepare substation operation data for the analysis. The Company will address the effect of incremental DERs by also calculating a "counterfactual" load factor, including the development of 8,760 load shapes, by backing out incremental additions of solar, demand response, heat pumps, EVs, and energy storage. This approach is detailed further in the table below.

Inputs	• Historical hourly loads • Historical monthly load modifier additions (heat pumps, solar, batteries) • Load shape assumptions for load modifiers

Calculation	• Load Factor= Average load/max load
	• Done for two different datasets (no weather normalization)
	  o Actual loads
	  o Counterfactual loads: actual load plus *incremental* load modifiers * shapes

Outputs	• Annual load factor for each substation (not normalized) • Change in load factor from previous year (Actual LF_[y]- Actual LF_[y-1]) • Portion of change in load factor attributable to load modifiers (Actual LF_[y]- Counterfactual LF_[y])

d. Achievement

This is tracking-only metric with no specific targets. The Company will report Load Factor data in its annual EAM Report.

6. Residential Energy Intensity Scorecard Metric

a. Description

This metric tracks residential customers' total usage on a per customer basis.

b. Metric

This metric is measured as the annual residential MWh sales (Service Classes 1 and 6) divided by the 12-month average number of residential customers.

c. Measurement

This metric will be measured as the annual residential MWh sales divided by the 12-month average number of residential customers. Within this calculation the annual residential MWh sales will be: 1) normalized to correct for the weather-related impacts on electricity sales, 2) reduced by the aggregate MWhs produced by Community Distributed Generation resources and allocated to residential customers through the value stack tariff, and 3) adjusted to exclude the impacts of beneficial electrification such as new load from heat pumps and electric vehicles.

The Residential Electric Energy Intensity metric will be calculated as:

$$\frac{(\text{weather normalized MWh sales}) - (\text{MWh CDG allocations}) - (\text{MWh sales associated with EVs or Heat Pumps})}{\text{12 month average residential customers}}$$

d. Achievement

This metric is tracking-only with no specific targets. The Company will report Residential Energy Intensity data in its annual EAM Report.

7. <u>Commercial Energy Intensity Scorecard Metric</u>

a. Description

This metric tracks commercial customers' total usage on a per customer basis.

b. Metric

This metric is measured as the annual commercial MWh sales divided by the 12-month average number of commercial customers.

c. Measurement

The Commercial Electric Energy Intensity metric measures the reduction of commercial (Service Class 2 non demand) customers' total usage on a per customer basis. This metric will be measured as the annual commercial MWh sales divided by the 12-month average number of commercial customers. Within this calculation the annual commercial MWh sales will be: 1) normalized to correct for the weather related impacts on electricity sales, 2) reduced by the aggregate MWhs produced by Community Distributed Generation resources and allocated to commercial customers through the value stack tariff, and 3) adjusted to exclude the impacts of beneficial electrification such as new load from heat pumps and electric vehicles. The Commercial Electric Energy Intensity metric will be calculated as:

$$\frac{(\text{weather normalized MWh sales}) - (\text{MWh CDG allocations}) - (\text{MWh sales associated with EVs or Heat Pumps})}{\text{12 month average commercial customers}}$$

d. Achievement

This metric is tracking-only with no specific targets. The Company will report Commercial Energy Intensity data in its annual EAM Report.

8. <u>Gas Peak Reduction Scorecard Metric</u>

a. Description

This metric measures the gas system peak reductions that provide additional system benefits and lower supply costs to customers. To the extent that there is a decline in the actual weather adjusted gas system peak below the prior rate year baseline level established for the Gas Peak Reduction ("GPR") metric. (NOTE: Weather adjusted refers to the extrapolation of realized historic data up to the design day temperature in order to take into account the level to which the Company plans the necessary capacity, supply, and demand response system resources to meet firm customer demand during extreme winter peaks.)

For this metric, the Company will use a five-year historic window of gas peak days, taking the five highest points of firm heating send-out each year and removing summer base load, to develop a trend line. These peaks are extrapolated, or weather adjusted, to the design day temperature since this is the level to which gas companies would plan for each year.

As a matter of practice, gas utilities forecast short-term daily throughput volumes, for a combination of sales and transportation customers, to ensure reliability. This covers both the current day as well as going out for up to an additional week. The gas utilities compare these forecasts with actual historical data to help identify patterns of load changes, taking into account variables such as weather, days of the week, time of year and holidays. By using this methodology, these factors are being included.

b. Metric

The "heat factor" for the five highest peak day send-outs is first calculated for each of the five years prior. The peak day winter send-out will be calculated as measured, then adjusted to remove the effects of: (i) interruptible customer or non-firm usage; and (ii) baseline non-heating firm gas usage. Interruptible or non-firm customer usage shall not be included as part of peak day usage. Baseline non-heating usage will be determined as an average of the five highest send-outs during the preceding summer, less interruptible and daily-metered customer usage (all non-firm, on those summer peak days). For each of the prior five years, the peak day send-outs for the five highest peak days will be divided by the corresponding peak day HDDs to determine a heat factor. Those heat factors are then used to extrapolate each of the peak day send-outs to the design day temperature (-8 degrees F). This is done by multiplying the heat factor by the difference between the design day's 73 HDDs and a particular peak day's HDDs and adding that result to that particular peak day's send-out. A simple linear regression is run on the 25 data points derived from the five highest peak day send-outs for the five years prior, extrapolated to the design day temperature, to determine a trendline and standard deviation.

c. Measurement

The current year's weather adjusted peak day send-out will be determined as detailed above and measured against the target reduction levels to determine achievement. The current year's five highest weather adjusted peak day send-outs will then be included in a new regression model to determine next year's target levels as explained above. The standard error of the regression will always use the most recent five years of historical data. For example, the 2025 metric (Winter 2024/2025) will use the five-year historical period from Winter 2019/2020 through Winter 2023/2024.

d. Achievement

This metric is tracking-only with no specific earning targets. The Company will report Gas Peak Reduction data in its annual EAM Report.

9. EV Adoption EAM

a. Description

The EV Adoption EAM incentivizes the Company to reduce greenhouse gas ("GHG") emissions by facilitating greater penetration of EVs. EVs reduce GHGs relative to traditional internal combustion engine vehicle technologies that rely on emissions-intensive fuel sources like gasoline and diesel.

b. Metric

The EV Adoption metric is an outcome-based metric and will be measured as the incremental lifetime metric tonnes ("tonnes") of avoided CO_2 from incremental EVs registered in Central Hudson's service territory. EVs are defined as battery electric vehicles ("BEVs") and plug-in hybrid electric vehicles ("PHEVs"). BEVs and PHEVs have lifetime avoided emissions factors due to their distinct fueling profiles, where BEVs displace a greater number of gasoline miles annually than do PHEVs.

c. Measurement

Incremental lifetime tonnes of CO_2 will be calculated as the number of incremental vehicles of each type multiplied by that type's assumed avoided tonnes of CO_2 multiplied by the average vehicle lifetime. Performance will be based on publicly available vehicle registration data as published on the Atlas Public Policy – EvaluateNY website.

Battery electric vehicles (BEVs): BEV registrations * 4.1 tonnes CO_2 * 10 years

Plug-in hybrid electric vehicles (PHEVs): PHEV registrations * 3.1 tonnes CO_2 * 10 years

d. Achievement

To determine achievement, lifetime tonnes of CO_2 savings from BEVs and PHEVs in the Company's service territory will be added together and measured against the target levels identified below.

EV Adoption EAM Targets (Lifetime CO_2 Tons)	**Target**	**2026**	**2027**	**2028**
	Minimum	302,860	393,880	489,907
	Midpoint	435,417	671,173	1,001,217
	Maximum	567,974	948,466	1,512,527

Reporting

The Company will submit its Annual EAM report by June 1st of each year for the prior calendar year. Annual reports should describe any EM&V activities applicable to EAM performance.

Attachment B

SUBJECT: Filings by CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Amendments to Schedule P.S.C. No. 15 – Electricity

Third Revised Leaves Nos. 106.1.5, 106.1.11, 163.9.2
Fourth Revised Leaves Nos. 106.1.9, 272.17.8
Fifth Revised Leaves Nos. 163.9.7, 184.5
Seventh Revised Leaf No. 184.3
Eighth Revised Leaves Nos. 94, 187, 205.1.1
Ninth Revised Leaf No. 137
Tenth Revised Leaf No. 210.1
Eleventh Revised Leaf No. 217.1
Twelfth Revised Leaves Nos. 163.5.3, 232
Thirteenth Revised Leaf No. 163.5.35
Fourteenth Revised Leaves Nos. 106, 272.3.2
Sixteenth Revised Leaves Nos. 135, 205.2
Seventeenth Revised Leaves Nos. 163.5.5, 218.2
Eighteenth Revised Leaf No. 163.5.2
Twentieth Revised Leaves Nos. 184.2.1, 231
Twenty-First Revised Leaf No. 219
Twenty-Second Revised Leaf No. 163.3
Twenty-Third Revised Leaves Nos. 165, 185, 218.1
Twenty-Fourth Revised Leaves Nos. 220, 222, 246
Twenty-Sixth Revised Leaves Nos. 205.1, 218, 226
Twenty-Seventh Revised Leaves Nos. 169, 246.1
Twenty-Eighth Revised Leaf No. 210
Twenty-Ninth Revised Leaf No. 205
Thirtieth Revised Leaves Nos. 104, 217

Suspension Supplement Nos. 135, 136, 137

Amendments to Schedule P.S.C. No. 12 – Gas

First Revised Leaves Nos. 211, 214
Second Revised Leaves Nos. 10, 204, 205, 208, 209, 210, 213
Third Revised Leaves Nos. 129.3.1, 207
Fifth Revised Leaf No. 129.3
Sixth Revised Leaf No. 4
Eighth Revised Leaf No. 63
Eleventh Revised Leaf No. 129.1
Twelfth Revised Leaves Nos. 124.1, 129.2, 137
Fourteenth Revised Leaf No. 126.2
Fifteenth Revised Leaf No. 181.1
Seventeenth Revised Leaves Nos. 121, 212
Twenty-First Revised Leaf No. 151
Twenty-Second Revised Leaf No. 206
Twenty-Fourth Revised Leaves Nos. 152, 158
Twenty-Fifth Revised Leaves Nos. 181, 188, 193

Twenty-Sixth Revised Leaf No. 126.1
Twenty-Eighth Revised Leaves Nos. 149, 186, 191

Suspension Supplement Nos. 73, 74, 75