Attachment A3

Central Hudson Brief on

Exceptions

NYPSC Case 23-E-0481

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service	:	Case 23-E-0418
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	:	Case 23-G-0419

BRIEF ON EXCEPTIONS OF
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May 21, 2024

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I. INTRODUCTION

On May 1, 2024, the Secretary to the Commission issued the Recommended Decision ("RD") of Administrative Law Judges James A. Costello and Ashley Moreno ("ALJs") for exceptions. Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company") appreciates the diligent and detailed analysis by the ALJs, although it does not agree with all of their determinations, and respectfully submits herein its exceptions to the RD in accordance with the Notice of Schedule for Filing Exceptions.

II. STATEMENT OF THE CASE

On July 31, 2023, Central Hudson filed tariff leaves and supporting testimony and exhibits for new rates and charges for electric and gas service to be effective July 1, 2024. The Company proposed to increase electric and gas revenues by $139.5 million and $41.5 million, respectively, for the twelve months ending June 30, 2025 ("Rate Year"). ALJs James A. Costello and Ashley Moreno were appointed to conduct a rate proceeding to review the Company's filing.

On September 8, 2023, the ALJs issued a ruling that adopted a schedule for the submission of Staff and intervenor testimony as well as rebuttal testimony.[1] The Company filed a Notice of Impending Settlement on January 5, 2024, and a settlement conference was held on January 10, 2024, resulting in resolution of certain issues via stipulation.

Evidentiary hearings were held over ten days between January 24, 2024, and February 6, 2024. Following the conclusion of the evidentiary hearings, the ALJs adopted a briefing schedule establishing deadlines for post-hearing briefs. To accommodate a briefing schedule that allowed sufficient time for parties to respond to recommendations contained in any Recommended Decision issued in these proceedings, the Company agreed to extend the maximum suspension period by 31 days, subject to a traditional "make-whole" provision.[2] Following the filing of briefs, the RD was issued on May 1, 2024.

III. SUMMARY OF CENTRAL HUDSON'S POSITION

These cases were fully contested rate cases, with numerous issues raised across a wide and deep evidentiary landscape. Central Hudson largely concurs with the recommendations contained in the RD and greatly appreciates the thorough and professional effort put forth by ALJs Moreno and Costello. The RD, however, is not without error and the Company respectfully takes exception to certain key elements of the RD. As to the RD's recommendations

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[1] 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, Ruling on Procedural Matters and Amending Protective Order (Sept. 8, 2023).

[2] Cases 23-E-0418 et al., Request to Extend Maximum Suspension Period (Mar. 14, 2024). The Company notes that the RD was silent on the request to extend the maximum suspension period subject to a "make-whole" provision. The Company, however, anticipates that the Commission's order in these proceedings will approve the Company's make-whole request, as is traditional. See Case 16-G-0257 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service, Order Establishing Rates for Gas Service at 94-95 (Apr. 20, 2017) ("2017 National Fuel Order"). The Company's make-whole calculations are provided in Appendix 3, Schedule G for the revenue requirements set forth in Schedule 1 to the RD and in Appendix 4, Schedule G for the revenue requirements inclusive of the Company's updates, corrections and exceptions identified herein.

to which the Company takes exception, they do not fairly consider the weight of the evidence proffered by the Company, rely on Commission precedent which is inappropriately applied to the facts presented on the record in these proceedings, are inconsistent with Commission policy, are inconsistent with the record evidence, or rely on erroneous conclusions.

Central Hudson's rate filings were prepared in a manner intended to balance the cost to customers during the Rate Year with the value provided through preserving the safety and reliability of the Company's electric and gas distribution systems. The Company seeks rate relief to allow it to replace infrastructure that is obsolete or beyond its useful life, support energy affordability, energy efficiency and heat pump programs, maintain the reliability and safety of the electric and gas distribution systems and continue to respond to storms and extreme weather events. The Company also seeks the ability to continue investments in modern electric infrastructure that will improve system resilience and advance the state's goals and policies as set forth in the Climate Leadership and Community Protection Act ("CLCPA").

Schedule 1 to the RD shows delivery revenue requirements of $75.4 million (electric) and $29.6 million (gas). As discussed in more detail in Section XVII, as directed by the Notice of Schedule for Filing Exceptions, the Company worked with New York State Department of Public Service Staff ("Staff") to develop bill impacts based on these revenue requirements, which are set forth in Appendix 3 to this Brief. The RD also recommends approval of certain updates. In addition, in reviewing the adjustments presented in the RD, the Company identified several adjustments requiring corrections to accurately reflect the intent of the RD's recommendations.[3] As shown in Appendices 1 and 2 (Schedule A), for electric and gas,

[3] The adjustments requiring correction are primarily formula and calculation errors that the Company identified in Staff's revenue requirement model and net plant models, which were used by the ALJs in preparing the schedules to the RD. The Company has discussed these corrections with Staff, which is reviewing them. A brief description of the corrections is set forth in Appendices 1 and 2 (Schedule D).

respectively, the updates authorized by the RD coupled with the required corrections produce an electric delivery revenue requirement of $73.5 million and a gas delivery revenue requirement of $26.5 million. The Company also developed bill impacts for the updated and corrected revenue requirements and has presented them in Appendix 4. Finally, Appendices 1 and 2 (Schedule A) for electric and gas, respectively, also quantify the effects of the Company's exceptions to the RD and provides revenue requirements (inclusive of the updates and corrections) of $102 million for electric and $37.0 million for gas.[4] The evidentiary record establishes that the Company's proposed revenue requirement is necessary for Central Hudson to continue to provide safe, adequate and reliable electric and gas service at just and reasonable rates.

The Commission should decline to adopt the RD wholesale and instead grant the Company's exceptions set forth below. Should Central Hudson's exceptions not be adopted, the Commission would: deny the Company the ability to generate sufficient revenues to compensate it for the costs of providing safe and reliable service to its customers; deny the Company the resources needed to provide safe and adequate service and achieve performance targets; and deny the Company an authorized return on equity and equity ratio that would provide investors with a return commensurate with that available from entities with similar risks, thus jeopardizing the Company's ability to access capital on reasonable terms.

The Commission's ultimate determination in these rate cases must properly be based on the record evidence before it, which fully supports the Company's recommended revenue requirement. The Commission should be particularly mindful of the serious consequences that will arise from ignoring the factual record and universally adopting the RD. Not the least among

[4] Also attached to this Brief is Appendix 5, which includes the following schedules that the Company believes should be updated and appended to the Commission's order to reflect the final outcome of these rate case proceedings: revenue matched factors, deferral listing, major storm reserve and depreciation factors.

such consequences is the potential for further deterioration of the Company's credit metrics, which could lead to a credit downgrade. Should Central Hudson be downgraded, the costs to customers would be high and rate relief sufficient to restore an appropriate bond rating would take years and have far reaching results, not only for the Company but for all New York utilities.

Accordingly, Central Hudson notes the following exceptions to the RD:

V. EXPENSE ISSUES[5]

A. Operations and Maintenance

1. Site Investigation and Remediation ("SIR")

The Company takes exception to the RD's recommendation that the Company file with the Commission internal audits of the Company's SIR Program. RD, pp. 25-26. To be clear, the Company does not except to conducting the audits before the end of the Rate Year - the Company's exception is limited to the RD's recommendation that these audits be filed. The RD erroneously imposes a filing requirement that is neither part of Staff's recommendation in these proceedings nor otherwise supported by the record. Tr. 3494. Further, the Company does not generally file highly confidential internal audit reports but makes them available to Staff for review at the Company's premises upon request. That approach should be followed here, since filing the SIR Program audits was not part of Staff's recommendation in these proceedings.

3. Labor Expense

a. Incremental Full-Time Equivalents ("FTEs")

The Company initially requested a staffing increase of 254 incremental FTEs during the bridge period to the end of the Rate Year.[6] The RD states that Staff recommended a reduction of

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[5] The section headings that follow align with the headings utilized in the RD for the topic being addressed.

[6] Exhibit 257 (WCBP-2R) shows a total of 269 positions. However, due to attrition only 254 of those positions are considered incremental FTEs. Further, the Company agreed to pursue its Assistant Engineer position related

122.5 of the Company's incremental FTEs.[7] Exhibit 302 (SAP-4 Corrected). The RD notes discrepancies between the presentation of incremental FTEs in the Company and Staff Initial Briefs. As an initial matter, the Company organized the presentation of incremental FTEs in its Initial Brief by the Company panel that supported the request.[8] Further, Exhibit 257 (WCBP-2R) lists the Company panel that supported each incremental FTE in either direct or rebuttal testimony. The Company will address each of the discrepancies noted in the RD in the applicable sections below, while taking exception to the RD's recommendation to disallow specific FTEs.

1. Electric Capital and Operations

(a) Assistant Engineers

The RD seeks clarification on the actual number of Assistant Engineer (Grid Modernization) and Assistant Engineer (Substation) positions at issue, as the briefing was difficult to follow. RD, p. 31. As the RD states, and as reflected in Exhibit 257 (WCBP-2R), the Company requested three Assistant Engineer (Grid Modernization) positions during the bridge period to the end of the Rate Year.[9] In testimony, Staff recommended allowing one of these positions. Tr. 2587. However, Exhibit 302 (SAP-4 Corrected), which was provided following

to the Company's Utility Thermal Energy Networks ("UTEN") in the Commission's generic UTEN proceeding, thereby reducing the Company's total incremental FTE request to 253 FTEs. The Company's Initial Brief mistakenly stated that the total incremental FTE request was 254 FTEs.

7 In Staff's Initial Brief, Staff stated that it recommended rejection of 122.5 of the Company's proposed FTEs. However, in Staff's Reply Brief, Staff acknowledges that one of these positions should be added back to the Company's Rate Year revenue requirement. Staff Reply Brief at 57.

8 There were incremental FTEs that were not specifically supported by a Company panel – those are listed in the Initial Brief in the "Miscellaneous Incremental FTEs" section. These FTEs are not at issue in this brief.

9 Staff notes in testimony that the Company requested three positions during the bridge period to the end of the Rate Year, and two positions through June 2026 (which would be in a Rate Year 2) and uses five as the total number of positions. Tr. 2586. It is possible that Staff's reference in its Initial Brief to five Assistant Engineer (Grid Modernization) positions includes two positions that were not intended to be filled by the end of the Rate Year.

Staff's testimony in these proceedings, reflected the removal of three Assistant Engineer (Grid Modernization) positions proposed by the Company. Due to this discrepancy between Staff testimony and Exhibit 302 (SAP-4 Corrected), the Company's Initial Brief indicated that there were three Assistant Engineer (Grid Modernization) positions at issue.[10]

The Company also requested three Assistant Engineer (Substation) positions, as demonstrated in Exhibit 257 (WCBP-2R). Staff recommended allowing one of these positions, as reflected in testimony and Exhibit 302 (SAP-4 Corrected). Tr. 2590. As a result, Appendix 2 to the Company's Initial Brief identified two Assistant Engineer (Substation) positions at issue. In summary, the Company requested three Assistant Engineer (Grid Modernization) and three Assistant Engineer (Substation) positions during the bridge period to the end of the Rate Year, of which three Assistant Engineer (Grid Modernization) and two Assistant Engineer (Substation) positions remain at issue.

This clarification brings the total number of positions to six, instead of the eight mentioned in the RD – however, the four FTEs recommended for allowance by the RD should be maintained for the reasons discussed therein.

2. Gas Capital and Operations

(c) Assistant Engineer

The Company excepts to the RD's recommendation to disallow an Assistant Engineer position needed for the implementation of the Pipeline Safety Management System ("PSMS"). RD, pp. 42-43. The RD mistakenly agrees with Staff that the Company did not make an "adequate demonstration" of the need for this incremental FTE. Id. The RD also cites to Staff's

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[10] Appendix 2 to the Company's Initial Brief included a number in parentheses next to the positions for which more than one FTE was requested. This number was intended to identify the positions at issue. For example, Assistant Engineer (Grid Mod) (3) would indicate three positions at issue.

concerns with the Company's pace in developing the PSMS as justification for disallowing the position. Id. The RD errs by disallowing this position. First, Exhibit 61 (SPSP-1), pages 31-32, details the PSMS implementation tasks associated with the Company's proposed Assistant Engineer position. Further, denying the position because the Company has not made sufficient progress on PSMS implementation is counterintuitive. As the Company stated in Appendix 2 to its Initial Brief, this position is necessary for the Company to make tangible PSMS progress. Therefore, this position should be approved by the Commission.

5. Customer Service

The RD seeks clarification regarding the Company's proposed incremental customer service FTEs and Staff's recommended disallowance of those FTEs. RD, p. 48, fn. 166. As provided in the Company's Initial Brief, the Company's Customer Experience Panel supported the need for 94 incremental FTEs. Exhibit 257 (WCBP-2R). The Company's Exhibit 257 (WCBP-2R) identifies 13 incremental FTE positions supported by the Company's Customer Experience Panel that were recommended for allowance by Staff: four Consumer Outreach Representative positions (to be filled in 2023), six Accounting Technician 3/C (Billing) positions (to be filled in 2023), two additional Consumer Outreach Representative positions (to be filled by June 30, 2024) and one Meter Reading Supervisor position (to be filled by June 30, 2024), for a total of 13 incremental FTE positions. The Company believes this accounting to be accurate, as it is consistent with Staff's Exhibit 302 (SAP-4 Corrected).

As a general matter, the Company excepts to the RD's disallowance of a number of incremental customer service FTEs, as the RD does not take into account the attrition that was built into the Company's incremental FTE request. The Company's Exhibit 257 (WCBP-2R) removes five customer service FTEs (reflected as the Customer Services Headcount Reduction of -5) from the incremental positions to be filled in the Rate Year to reflect attrition.[11] To the extent the Commission adopts the RD's recommendation to disallow an incremental customer service FTE, it must also remove the built-in negative position. Currently, the RD inappropriately disallows the incremental position without removing the negative position.

(b) Billing

The Company excepts to the RD's recommendation to disallow all billing-related FTEs. RD, p. 55. First, the Company would like to clarify the appropriate number of proposed incremental billing-related FTEs and the associated function of these FTEs. As stated in the Company's direct testimony, the Company requested 11 incremental positions in the Company's Customer Billing Department.[12] Tr. 3022. While some of these incremental positions would be responsible in part for supporting complex billing scenarios,[13] all of these positions would be responsible for supporting the Company's collections efforts. Exhibit 257 (WCBP-2R). Therefore, the Company maintains that these billing-related FTEs should be evaluated as part of the RD's discussion on collection-related FTEs. These positions should be approved, as the justification and need for these employees is similar to the field collectors and supervisor positions recommended for approval in the RD.

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[11] For example, the Company requested 49 total incremental FTEs in the Rate Year but reduced that number to 41 to reflect attrition. Five of those reduced positions are specific to customer service. Exhibit 257 (WCBP-2R).

[12] These positions are identified as Accounting Technician 3/C Billing (7 positions), Customer Support Analyst (Billing) (2 positions), Business Analyst (1 position), and Business Analyst (Billing) (1 position). The Company notes that the Business Analyst (Billing) position is mislabeled in Exhibit 257 (WCBP-2R) as part of the Technology initiative. The Company also notes that Staff's Exhibit 302 (SAP-4 Corrected) allows six of the Accounting Technician 3/C Billing positions – therefore, the number of billing-related FTEs at issue is five.

[13] As it relates to complex billing scenarios necessitating incremental resources, the RD "agree[s] with Staff that the Company's justification for these specific positions is based more on speculation than a demonstrated need." RD, p. 54. Since the issuing of the RD, this conclusion has already been contradicted. On May 15, 2024, the Commission issued two orders in Case 21-E-0629, both of which will require Company implementation of new billing changes. See Case 21-E-0629 - In the Matter of the Advancement of Distributed Solar, Order Approving Statewide Solar for All Program with Modifications (May 16, 2024); Case 21-E-0629 - Order Approving Multiple Savings Rates for Community Distributed Generation Subscribers (May 16, 2024). These new billing changes are in addition to the 19 billing changes cited in the Company's Reply Brief on page 18.

(c) Collections

The Company excepts to the RD's discussion of the Company's proposed collections-related incremental FTEs, which results in the allowance of 10 field collectors and one supervisor FTE. RD, p. 60. While the Company appreciates the RD's recommended allowance of these positions, the RD errs by not discussing or considering all of the Company's incremental FTEs associated with collections efforts. As demonstrated in Exhibit 257 (WCBP-2R), the Company requested 58 collections-related incremental FTEs and Staff recommended allowance of six of these FTEs. Exhibit 302 (SAP-4 Corrected). This leaves 52 incremental positions at issue, which is reduced to 41 positions including the 11 positions recommended for allowance in the RD. The Commission should approve these positions as the justification and need for these employees is the same as for the field collectors and supervisor recommended for approval in the RD.

Specifically, the RD errs by failing to consider the Company's evidence demonstrating that customer interactions associated with collections activity are expected to grow significantly, necessitating incremental FTEs. The RD states "[t]he Company does not cite to any discussion of its existing employees' ability to perform these functions relative to the number of collections calls…" to justify the disallowance of billing-related FTEs.[14] RD, p. 53. The RD also states that the Company's Exhibit 111 (CEP-4R) contains no discernable incremental FTE count. RD, p. 52. This is not supported by the record. In testimony, the Company's Customer Experience Panel stated that 33 incremental customer service representatives were necessary to handle the increased customer interactions resulting from collections activities. Tr. 3020. The Company's Exhibit 111 (CEP-4) provides support for these 33 incremental FTEs and demonstrates the

[14] While the RD discusses these FTEs in the Billing section, these FTEs are more appropriately discussed in the context of collections.

projected call volume increase associated with the resumption of collections.[15] Therefore, the record demonstrates the Company's need for these incremental positions. These 33 incremental FTEs should be approved by the Commission as necessary for the Company's collections activities.

6. Climate Leadership and Sustainability

The Company takes exception to the RD's recommendation to allow zero incremental FTEs. As discussed below, the record demonstrates that the Company requested two incremental positions, both of which were supported by Staff. The RD seeks clarification regarding a discrepancy between the Company and Staff regarding the presentation of this item in briefs. RD, p. 63. The Company's Climate Leadership and Sustainability Panel supported two incremental FTEs – an Associate Sustainability Coordinator and a Program Manager of Distributed Energy Resources. Tr. 2814-2816; Exhibit 257 (WCBP-2R). Staff recommended allowance of both of these FTEs. Exhibit 302 (SAP-4 Corrected). In Staff's Initial Brief, Staff discusses the Assistant Engineer associated with the Company's UTEN efforts under this section heading. However, this position was supported by the Company's Workforce, Compensation and Benefits Panel. Exhibit 257 (WCBP-2). Therefore, the Company did not include this position in its discussion of Climate Leadership and Sustainability FTEs in its Initial Brief. The Company believes this to be a difference in presentation and not a disagreement with Staff on this issue.

7. Accounting and Tax

The Company takes exception to the RD's recommendation to allow five incremental FTEs related to accounting and tax positions. RD, p. 63. As discussed below, the record

[15] The RD refers to this exhibit to support its finding regarding the Company's request for call volume overflow costs. RD, pp. 125-129. The exhibit similarly supports the Company's request for the 33 incremental customer service representatives.

demonstrates that the Company requested seven incremental positions, all of which were supported by Staff. The RD seeks clarification regarding a discrepancy between the Company and Staff regarding the presentation of this item in briefs. RD, p. 63. The Company's Accounting and Tax Panel supported seven incremental FTEs.[16] Staff recommended the allowance of these incremental FTEs. Exhibit 302 (SAP-4 Corrected). In Staff's Initial Brief, Staff discusses the incremental FTEs proposed for the Company's Training Department under the header Accounting and Tax FTEs. The FTEs discussed by Staff were supported by the Company's Workforce, Compensation and Benefits Panel. Exhibit 257 (WCBP-2R). Therefore, the Company did not discuss these positions in the section of its Initial Brief regarding Accounting and Tax FTEs. The Company believes this to be a difference in presentation and not a disagreement with Staff on this issue.

b. Vacancy Rate

The RD acknowledges that Staff's proposed vacancy rate "may not accurately reflect when [vacant] positions will be refilled," but then inexplicably adopts Staff's vacancy rate concluding that "Staff's position, which is based on historical attrition rates provided by the Company, better reflects what can be anticipated during the Rate Year." RD, p. 66. The RD errs in adopting Staff's proposal.

While the Company agrees that it will experience some level of vacancy during the Rate Year, reducing its labor expense forecast to reflect those vacancies is only appropriate if the Company's actual Rate Year labor expense is expected to be lower than its forecasted labor

[16] These positions are reflected in Exhibit 257 (WCBP-2R) as Accountant, Supervisor Tax Accounting, four Accounting Technician 3/C positions, and a Business Analyst.

expense.[17] There is no evidence to support such a position and indeed the record establishes the opposite is true. Specifically, the Company's actual headcount has historically exceeded the headcount allowed for in rates (see Exhibit 247 (RRP-7R)) and the Company expects this trend to continue in the Rate Year. Tr. 779. Because the Company's actual FTE level is likely to be higher than its forecasted FTE level, the RD's acceptance of Staff's vacancy rate is inappropriate.

Similar to Staff, the RD incorrectly conflates attrition with vacancy. As Staff acknowledged during cross-examination, employee departures (attrition) do not necessarily create permanent vacancies. Tr. 4161-4162. Moreover, the RD concedes that "Staff's position may not accurately reflect when [vacant] positions may be refilled during the year." RD, p. 66. In fact, the vacancy rate adjustment has the effect of denying an entire year's worth of expense regardless of how long the position was vacant. Tr. 4164-4166. In doing so, Staff's vacancy rate goes beyond Staff's stated intent for the adjustment, which is to reduce wages that the Company will not incur "when positions are vacant during the year." Tr. 4059. Staff's vacancy rate adjustment is thus inherently flawed and its adoption by the RD was in error.

The RD's concession that Staff's position may not accurately reflect when vacant positions may be refilled tacitly admits that the vacancy rate adjustment results in denial of the Company's ability to recover legitimate and actual labor expense. Tr. 4164-4166. The fact that the Company has not reflected when "those positions are vacant during the year" is inapposite because, as noted above, the anticipated vacancies during the Rate Year are unlikely to result in actual labor expense being lower than the labor expense built into rates.

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[17] Case 28828 - Proceeding on Motion of the Commission as to the Rates and Charges of Jamaica Water Supply Company, Opinion No. 85-9, Opinion and Order Determining Revenue Requirement (Apr. 15, 1985) (rejecting Staff's adjustment to labor expense stating, "An examination of the actual levels of Jamaica's employees for the previous rate year shows that the lag in filling a substantial number of new positions has been closed. Since the predicted imbalance between actual and projected payroll expense has not developed, we adopt the Judge's recommendation and deny staff's exception.").

The RD further errs in adopting Staff's recommendation to apply the vacancy rate to incremental new hires. Although the majority of the Company's incremental FTEs are planned to start prior to the start of the Rate Year (Tr. 321), the Company factored in an assumption that staggered the hiring of new employees over time (Tr. 694-695). This resulted in a reduced labor expense for the Rate Year that reflects the possibility that those positions are vacant during a portion of the Rate Year – the exact intent of Staff's vacancy rate adjustment. Applying a vacancy rate to incremental FTEs double counts the Company's adjustment.

c. Labor Distribution Rate (% of labor charged to expense or capital)

The Company relied upon the Historic Test Year labor distribution, adjusted for projected changes, to determine the labor distribution between expense, capital, and other affiliates to be used in the Rate Year. RD, p. 67. For the last 30 years, the Company has relied upon – and the Commission has approved – this method to determine the labor distribution to be used in the projection of Rate Year labor expense.[18] Tr. 781.

In the instant proceedings, however, Staff recommends the use of a three-year average to determine the labor distribution rate, arguing that because the actual distribution will not be known until the final FTE number is fixed, the Company's proposed normalization methodology could result in a significant distortion of the labor distribution rate. Staff's proposed methodological change produces a $2.16 million expense reduction for electric operations and $539,000 for gas operations. RD, p. 67.

[18] Moreover, this very adjustment was proposed in the direct testimony of the Staff Accounting Operating Expense and Payroll Tax Panel in Cases 17-E-0459 and 17-G-0460 and was adopted in the calculation of the labor allocation, where it served to decrease the amount of labor being charged to electric and gas expense. Tr. 783. In Cases 20-E-0428 et al., the Company put forth this same adjustment, which again served to reduce the amount of labor being charged to electric and gas expense, and was accepted by Staff and used to set rates. Id.

The RD rejected over 30 years of past practice and adopted Staff's new approach (RD, p. 69), erring on several grounds. First, this methodology was not a mere settlement convention – it was approved by the Commission in multiple rate cases over at least three decades in both settled and litigated cases. Tr. 781, 783-784. Second, the Commission's 1977 Policy Statement on Test Periods in Major Rate Proceedings explicitly states that operating results for the rate period should be predicated on a historical test year with normalizing adjustments – precisely what the Company proposed here. Tr. 782-783. Third, the fact that the ultimate number of new FTEs is large and will not be known with certainty until the Commission determines their ultimate number is a reason to use the normalized historic year allocation and not a three-year average. Indeed, the way in which the new employees are likely to allocate their time between expense and capital will almost surely be different from the past, again negating the accuracy of a three-year historical average.[19] Contrary to the RD's finding, the Company included adjustments to the historic year labor distribution to account for known or anticipated changes in the Rate Year. Using a historical three-year average therefore does not reflect how the existing workforce allocated their time between expense and capital, and it ignores the projected effect that incremental employees will have on the overall labor distribution. Tr. 781-782. Finally, the fact that Staff seeks a methodological U-turn now when adoption of its new methodology would lower, rather than increase, labor expense is curious; suggesting it is the same sort of "heads I

[19] Customer service, billing and collection FTEs, for example, would be expected to bill little if any of their time to capital. Consequently, the Company's adjustment to the Historic Test Year to account for the new employees is surely more accurate than a three-year average that reflects a different employee mix and different capital-expense ratios.

win, tails you lose" approach that has earned the opprobrium of reviewing courts.[20] For all these reasons, the resolution reached by the RD should be reversed.

The Company notes, however, that the RD's recommendation to recover costs associated with the incremental meter reader FTEs through a surcharge instead of base rates (to which the Company does not take exception) impacts the Company's proposed labor distribution rate. Specifically, under the Company's methodology, removal of the incremental meter reader FTEs from base rates results in a labor distribution rate of 54.01% to electric expense and 15.26% to gas expense.[21] The Company submits this is the labor distribution rate that should be adopted by the Commission.

d. Wage Increases

With respect to the Systems Operation Union wages, the RD adopted Staff's projections of a 2.50% increase through the end of March 2025 and a 3.00% increase for the period beginning April 1, 2025. RD, p. 72. The 1977 Policy Statement on Test Periods in Major Rate Proceedings permits updates for known changes to be submitted in the Company's Brief on Exceptions. On April 1, 2024, the Systems Operations Union employees entered into a new Memorandum of Agreement ("MOA") that covers the period April 1, 2024 through March 31, 2028. The MOA provides for a 4.00% increase effective April 1, 2024, and a 4.25% increase effective April 1, 2025. A copy of the relevant MOA has been provided to Staff for its review.

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20 Duquesne Light Co. v. Barasch, 488 U.S. 299, 315 (1989) ("Consequently, a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions."); Matter of Nat'l Fuel Gas Distrib. Corp. v. Pub. Serv. Comm'n of the State of N.Y.., 169 A.D.3d 1334, 1336, fn. 1 (3d Dept. 2019) ("Although petitioner expresses concern that the Department will change methods to whichever one provides for less of a rate increase, a staff member testified that the NY-Only method should be consistently used going forward for future rate proceedings. We assume that respondent will hold the Department to this position.").

21 Staff is able to verify this change using the Company's 'Labor-Adjusted Labor Distribution' workpaper.

Consequently, the wage increases of 2.50% and 3.00% in the RD should be replaced with increases of 4.00% and 4.25%.

With respect to Executive and Non-Union Management Employee wages, the RD appropriately rejected Staff's misguided recommendations to drastically reduce (Non-Union Management) or deny (Executive) wage increases due to SAP CIS implementation issues. But the RD then errs in rejecting the Company's recommended 4.5% increase for Executive and Non-Union Management Employees in favor of a 4% increase that Staff would have recommended absent the "extenuating factors."[22] RD, p. 76. The RD offers no rationale for why Staff's "normal methodology" is superior to the Company's methodology. Likewise, the RD did not identify any concerns or deficiencies with the Company's methodology. In fact, the RD simply ignores, without explanation, the following uncontroverted evidence: 1) the Company's proposed 4.5% wage increase for Non-Union Management Employees reasonably reflects the mid-point of Mercer's (a nationally recognized compensation consultant) conclusion that an increase in the range of 4% to 5% would be appropriate (see Schedule B of Exhibit 66 (WCBP-4)); and 2) the Company's proposed wage increase of 4.5% wage increase for Executives is reasonable based on the recommendation from Frederic W. Cook & Co., Inc., a nationally recognized executive compensation consultant. Given that the Company has met its burden of proof on these issues, the RD's determination to increase Executive and Non-Union Management Employees by 4% only should be reversed.

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22 At page 76, the RD states: "[b]ased on the record before us, we recommend that the Commission adopt a four percent wage increase for nonmanagement and executive employees, which Staff found appropriate absent 'extenuating factors.'" Given that the heading of this subsection refers to Executive and Non-Union Management Employees, the Company believes that the reference in the quote to "nonmanagement" and Executives is a typo and was intended to refer to Non-Union Management Employees. If that was not the intent of the RD, the Company requests clarification and leave to respond appropriately.

10. Major Storm Reserve

Using a 10-year average of major storms, the Company proposed a Rate Year expense allowance of $14.82 million. The Company demonstrated that its requested major storm reserve allowance was essential because the storm allowance in the 2021 Rate Plan produced an under recovery in excess of $60 million. RD, pp. 112-113. The RD, although adopting the use of a 10-year average, agreed with Staff's approach to remove two alleged "superstorms" reducing the Company's requested Major Storm O&M expense allowance by $4.064 million.
RD, p. 113. The RD found that "Staff's normalization of the ten-year average of historical costs to remove two outlying events should provide a more accurate forecast of what is likely to occur during the Rate Year." RD, p. 115. History, logic and the record counsel otherwise.

First, Staff's categorization of the two storms removed as "superstorms" is arbitrary given there is no criterion explained for such a removal or a basis for doing so other than a view that restoration expense related to these storms exceeded a certain threshold.

Second, such storms are not outliers. A review of storm data back to 2010, almost 13 years of data, shows that the Company has had multiple storms that resulted in restoration costs in excess of $10 million and two storms that exceeded costs of $20 million. Tr. 790.[23]

Finally, and as the Company's Revenue Requirement Panel explained:

[23] As the Company pointed out in its Initial Brief, Staff's removal of "superstorms," is curious given that the opening stanzas of the CLCPA proclaim that "[t]he adverse impacts of climate change include: an increase in the severity and frequency of extreme weather events, such as storms, flooding, and heat waves, which can cause direct injury or death, property damage, and ecological damage…" Staff also apparently forgot its own testimony in Cases 17-E-0459 and 17-G-0460 that: "[m]ajor storms are volatile and unpredictable, but over time, the Company should not be left with a storm reserve that is significantly over or under funded." Tr. 790. Staff's inherent position that storms are not getting increasingly stronger also stands in direct conflict with its White Paper on Review of Certain Pole Attachment Rules dated December 18, 2023 in Case 22-M-0101, where Staff stated (p. 44): "In recent years, there has been increased awareness and need for the electric system to be able to withstand increasingly severe storm conditions associated with climate change being experienced across the country and in New York State. On February 24, 2022, the Governor passed a new law (Chapter 45) focusing on how the State's electric utilities address climate change vulnerability and increase their storm hardening and system resiliency efforts." ("2023 Whitepaper").

> Staff's practice of removing storms they deem as "outliers" or "superstorms" from the historical average directly contradicts Staff's stated goal of the reserve and will continue to create challenges. In other words, underfunding the reserve in the past is precisely why the Company has accrued a regulatory asset in excess of $60 million for major storm restoration.

Tr. 790.

The path that led to the current $60 million underfunding of the storm reserve is the very same path advocated for by Staff and adopted by the RD. This is easily understood by looking at the last few Company rate cases. The Company's 2018 Rate Plan determined storm expense based on the elimination of so-called superstorms. That led to Central Hudson's storm reserve being underfunded by approximately $11.5 million, as of March 31, 2020.[24] In the 2021 Rate Plan, Central Hudson calculated a 10-year average resulting in a $9.7 million annual expense but reduced that amount to $4.7 million to moderate the rate impact and reflect "more recent experience."[25] In that case, Staff's removal of superstorms from the calculation resulted in an average of approximately $4.5 million, so Staff accepted the Company's reduced calculation.[26] Now the storm reserve is underfunded by $60 million. The RD should be reversed because the removal of so-called "superstorms" both ignores reality and has produced a significant underfunding of the Company's storm reserve – precisely the situation Staff claimed should be avoided.

B. Depreciation Expense

The Company initially proposed a new depreciation study ("Study") for informational purposes but, as the RD recognizes, in rebuttal "agreed with Staff's proposal to update the

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24 Cases 20-E-0428 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Prepared Testimony of Staff Accounting Panel at 41-42 (Dec. 22, 2020).

25 Id. at 43-44.

26 Id.

depreciation rates, insofar as doing so would 'provide[] a more appropriate and timely cash recovery in line with the cost causation principle' and, at least with respect to gas infrastructure, 'align[] with the goals of the [CLCPA].'" RD, p. 131. The RD next considered average service lives ("ASLs"), reaching a determination that Staff's adjustments to the Company's Study should be accepted but for various accounts noted on page 134 of the RD, finding that "certain of Staff's recommended ASLs deviate unrealistically from those in the Study, as well as from comparative data and industry standards, sometimes by as much as 15 years." The Company accepts the RD's resolution of the ASLs and agrees with the RD's rejection of Staff's attempt to change the salvage rates used in the Study. RD, p. 138.

The Company excepts, however, to the RD's resolution of the appropriate amortization period for the reserve deficiency.[27] The RD states that "the Company maintains that its initial proposal to recover, over a ten-year period, [the reserve deficiency of] $47.2 million for electric, $33.0 million for gas, and $1.3 million for common should be adopted."[28] Although mindful that waiting until the expiration of 20 years could leave the Company in a "tenuous position" with respect to the 2050 target in the CLCPA, the RD nevertheless agreed with Staff that the 20-year amortization period is "typical." RD, p. 139. The RD also determined that it was more

[27] The RD states that "the Company and Staff do not dispute that, applying the parameters identified in the Study, the Company's accumulated depreciation reserve balance is under-reserved by about $135.9 million, which is 18.7 percent of the June 30, 2022, balance, with $92.3 million attributed to electric (22.9 percent of the balance), $33.0 million to gas (21.8 percent of the balance), and $10.6 million for common (11.5 percent of the balance)." RD, pp. 138-139. Because the RD proposed adjustments to ASLs (to which the Company does not except), the reserve must be recalculated to reflect those ASLs that differ from the ASLs in the Study. Those new amounts result in the Company's accumulated depreciation reserve balance being under-reserved by about $85.5 million, with $64.1 million attributed to electric (15.9 percent of the balance), $18.1 million to gas (11.9 percent of the balance), and $3.3 million for common (3.6 percent of the balance).

[28] The RD first appears to believe that this proposal was premised on recovering the excess of the deficiency over a 10% deviation over a period of ten years. That is true for electric and common plant, but the Company's proposal was to recover the entirety of the gas plant's reserve deficiency over ten years. See Company's Reply Brief, p. 41. The description of the process, which describes the elimination of the gas deficiency after ten years, seems to correct that misapprehension. RD, p. 139.

appropriate to await the Commission's guidance in the Gas Planning Proceeding before making any change to the amortization period. RD, p. 140. The Company excepts to this finding and asks the Commission to provide this important guidance in these rate cases.

The notion that a 20-year amortization period is set in stone is unsupported. Consolidated Edison, for example, has twice seen its reserve deficiency amortized over a 15-year period; in 2008[29] and in 2017.[30] More to the point, the appropriate period for amortizing the reserve deficiency should be based on the facts and circumstances extant. For example, during a time of similar change for the telephone industry, a seven-year amortization was used for New York Telephone's reserve deficiency.[31]

The CLCPA promises to bring significant change to the natural gas industry in New York by 2050. With CLCPA deadlines looming in 2030 and 2050, the 20-year amortization adopted in the RD will permit collection of only the *excess* over 10% of the gas reserve deficiency by 2044, leaving the full remaining 10% (or more, depending on future depreciation studies) to depreciate over the six years remaining until 2050. This is not a tenable solution. Although the Commission may take additional evidence on depreciation in the Gas Planning Proceeding, there is no reason to exacerbate the issue of what to do with gas infrastructure by failing to amortize a "business-as-usual" reserve deficiency as rapidly as possible. The Company believes that, in keeping with precedent, the excess over 10% of the electric and common reserve deficiencies

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29 Case 07-E-0523 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Establishing Rates for Electric Service at 75 (Mar. 25, 2008) ("2008 Con Edison Order").

30 Cases 16-E-0060 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Approving Electric and Gas Rate Plans at 40-41 (Jan. 25, 2017).

31 Case 90-C-0191 - N.Y. Tel. Co. Rates, Opinion No. 91-4 at 155 (Mar. 7, 1991) ("Staff considers its proposal, which it says would actually amortize the reserve deficiency in less than seven years, to be an aggressive approach in this sphere.").

should be amortized over 10 years. Given the timing set forth in the CLCPA, there is no need to wait for a final resolution in the Gas Planning Proceeding before addressing in this rate case the entirety of the Company's gas reserve deficiency by amortizing and eliminating it over a 10-year amortization period.

G. Deferrals[32]

2. Governmental, Legislative, and Other Regulatory Actions

Given its historical experience, the Company requested to continue deferral accounting treatment for significant, unforeseen costs during the Rate Year associated with governmental, legislative, and other regulatory actions. Staff opposed, and the RD rejected the Company's request finding:

> The risk of governmental, legislative, and other regulatory actions resulting in significant, unforeseen costs during the Rate Year is reduced as compared to the risk present under a multi-year rate plan. Moreover, if such action occurs during the Rate Year, it likely would impact all utilities, making it more appropriate for the Commission to address the deferral issue on a generic basis.

RD, p. 147. The RD's finding is in error. Continuation of this deferral mechanism is appropriate as the risk of governmental, legislative, or other regulatory action occurring is present regardless of the duration of the rate plan, and costs associated therewith are entirely outside the Company's ability to control, difficult to forecast, and non-discretionary. See Tr. 4182.

It is indisputable that New York State is pursuing comprehensive changes to its climate and energy policies and laws, including measures designed to meet CLCPA goals, which have the potential to impose significant costs on the Company on an unspecified timeline. The fact that the Commission may address a particular governmental mandate in a generic proceeding is

[32] The Company respectfully requests for clarity that the Commission append to its order in these proceedings a listing of all deferrals authorized thereunder, similar to Appendix F to the 2021 Rate Plan. A proposed deferral schedule is included in Appendix 5.

cold comfort because the Commission has looked to these same rate case deferral provisions when addressing cost recovery in generic proceedings.[33] If the Commission disallows this deferral mechanism, the Company could be left without an appropriate vehicle to recover prudent costs associated with governmental mandates occurring during the Rate Year.

For these reasons, the RD should be reversed, and the Company should be granted deferral authority for costs incurred by the Company to comply with governmental, legislative, and other regulatory actions or mandates.

7. Roadway Excavation Quality Assurance Act ("REQAA")

The RD recognizes that a deferral mechanism is appropriate for the REQAA as it relates to gas capital projects, and further recommends that "Staff may audit the Company with respect to any deferral costs, should it deem an audit appropriate." RD, pp. 153-154. In a footnote, however, the RD questions why flagging activities for electric line clearing and hazard tree removal would be determined by the REQAA and not the terms of the union contract.[34]

There are several reasons why such activities should be included in the deferral. First, as the RD notes, Staff concedes that such activities are covered by the REQAA, even going so far as to contend that "based upon historical Article 8 Prevailing Wage Schedules provided by the Department of Labor, 'Lineman-Tree Trimmers serving as 'Flag Person' in their duties have consistently maintained New York State minimum wage as their prevailing wage amount.'"

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33 See e.g., Case 19-G-0736 - In the Matter of the Rules and Regulations of the Public Service Commission, contained in 16 NYCRR - Proposed Amendments to Chapter III, Gas Utilities, Subchapter C, Safety, Part 255, Transmission and Distribution of Gas, to Improve Operator Qualification Programs, Memorandum and Resolution Adopting Amendments to 16 NYCRR Part 255 at 17 (Mar. 18, 2022) ("Any incremental costs [related to the new Operator Qualification requirements] may be deferred pursuant to the terms of the individual utility's rate plan.").

34 The RD appears only to ask a question and does not find that such activities should not be subject to the deferral for costs incurred under the REQAA. Nevertheless, for clarity, the Company will treat that as a finding for purposes of this brief.

Staff Initial Brief, p. 27. Second, as the Company's Reply Brief explained, Staff only cites to the hourly wage portion of the schedule, and fails to add the supplemental benefits, which are $10.48 per hour plus 4.5% of the hourly wage paid. Company Reply Brief, p. 9. Third, although the pricing may be based on the union contract, the employees and prices are those of the contractors, not the Company, and it is the contractors that will ultimately set the prices, subject to the REQAA. Tr. 2081. Finally, the RD notes that Staff has the right to audit the requests for deferral of costs under the REQAA. If Staff determines that a cost increase arises from causes other than the REQAA, Staff is free to recommend that such increase not be included in the deferral amount. For all these reasons, the costs for electric system flagging activities, as well as the gas capital impacts, should be included in the deferral mechanism.[35]

VI. RATE BASE ISSUES

A. Electric Capital

2. CATV Make-Ready Reconciliation Mechanism

The RD denied the Company's request for a CATV Make-Ready reconciliation mechanism finding it provided no specific information about the work it anticipates it will have to perform in the Rate Year. RD, p. 162. With all due respect, the purpose of a reconciliation mechanism is to provide for just such a fluid situation.

The Company properly termed this process "non-discretionary" and Staff's own 2023 Whitepaper confirms the Company's view.[36] Given the short timelines in the process, it is

[35] To the extent the Commission adopts the RD's recommendation with respect to the REQAA deferral, the incremental cost impacts that the REQAA will have on the Company's vegetation management program ($1.54 million) should be included in the revenue requirement for the Rate Year, as the Company will experience a cost increase associated with these activities. Tr. 2144-2145; Exhibit 199 (ECOP-4R). If the Commission grants the Company's exception regarding the REQAA deferral, no such adjustment is needed.

[36] In the 2023 Whitepaper, Staff explained the process by which utilities, such as Central Hudson, must respond to CATV attachment requests: "As it relates to timelines, the 2004 Pole Order requires that preconstruction

difficult to know how the Company is supposed to "explain when that work will begin or what portion of the work is anticipated during the Rate Year" with any specificity. The Company carefully explained in this regard that any forecast for these expenditures can be rendered instantly moot, such as when "a single entity notified the Company of plans that required surveying 34,322 poles and completing the associated make-ready work within a 1.5-year period." Tr. 2115.[37]

These costs are unpredictable and unavoidable. Requiring the Company to request a deferral of these costs would likely result in their non-collection, as they are unlikely on an individual basis to satisfy the dollar criterion for deferral approval. Given these circumstances, it is difficult to find a better example of a process that merits a reconciliation mechanism.[38]

B. Gas Capital

2. Regulator Station Projects

While the RD appropriately recognizes that Staff's methodology for determining the budget for Regulator Station projects does not accurately reflect historical inflation,[39] the RD errs

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surveys must be done 45 days after a complete application has been filed with a pole owner. After conducting a survey of the poles, the pole owner must send a make-ready work estimate to the attacher within 14 days of completing the survey. Attachers have 14 days from receipt of the estimate to accept and pay for the make-ready work. Owners must perform the make-ready work within 45 days of receiving payment from the attacher, and notify the attacher that make-ready is complete within three business days of completion." 2023 Whitepaper at 5.

[37] Nor, in such an event, can the Company simply reprioritize spending, as Staff suggested. In the Company's response to DPS-660, which is included in Confidential Exhibit __ (ECOP-2R), the Company provided DPS-660 Attachment 3 Confidential, which demonstrated that supporting this individual buildout alone would require a capital investment of $7.9 million. This would account for approximately 15% of the overall forecasted expenditures within the Distribution Improvement Category for 2024 and would hinder the Company's ability to execute its Capital Plan without deferring these incremental costs. Tr. 2115.

[38] See e.g., 2008 Con Edison Order at 52-54 ("Absent a reconciliation and deferred accounting, the Company states that it would not be able to recover unanticipated costs for contamination that may be found during field work," reversing the RD and allowing a reconciliation mechanism for SIR costs).

[39] Should the Commission deny the Company's exception, the Company agrees with the RD's modification to Staff's forecasting methodology to properly inflate the historical expenditures prior to determining the three-year historical average.

in not adopting the Company's budget for this category of projects. For the same reason the RD rejected Staff's proposed adjustment to the budget for Transmission projects – i.e., that Staff did not demonstrate that the Company's project-by-project estimates are unreasonable (RD, p. 168) – the Commission should reject any adjustments to the Company's forecast for Regulator Station projects. The RD, like Staff, does not explain why the Company's forecasting methodology (appropriately developed on a project-by-project basis) is wrong or inaccurate but, rather, blindly accepts that a three-year average adjusted for inflation produces a more accurate forecast.

The RD attempts to justify its differing approaches to the Transmission projects and Regulator Station projects by asserting that its recommendation as to the gas transmission projects "was predicated on the fact that Staff agreed with the Company's proposal with respect to the Pipeline Mega Rule work." RD, p. 171. The RD appears to misstate its own rationale for adopting the Company's budget for the Transmission projects. As explained on page 168, the RD accepted the Company's proposed Transmission budget because "Staff did not demonstrate that the Company's project-by-project estimates are unreasonable", and "it does not explain how [an important project for the reliability of the gas transmission system] work – let alone other gas transmission work – can be conducted under its proposal." In other words, the RD recognized that only "the Company's proposal [would] ensure appropriate funding for work that is mandated by law or needed for reliability of the gas transmission system." RD, p. 168.

Notably, the Company established that Staff's budget for Regulator Station projects suffers from the same flaw – it will not allow all such projects to move forward thereby needlessly jeopardizing the reliability of the Company's gas system. Tr. 1249. Here too, Staff failed to explain why the Company's forecasting methodology is wrong or inaccurate. Tr. 2193.

Indeed, Staff conceded that it "[did] not intend to remove any particular gas projects proposed by the Company." Exhibit 214 (GCOP-1R), p. 1.

Based on the foregoing, the Commission should reject the RD's recommendation and adopt the Company's proposed budget for the Regulator Station projects.

4. Distribution Improvements

For the Distribution Improvement category of projects, the RD "agree[s] that Staff's methodology does not account for updated cost increases" but then curiously does not adopt the Company's proposed budget, finding instead that "the best way to account for increased unit costs and to produce the most accurate budgets, would be to use the latest actual costs provided by the Company, adjusted for inflation."[40] RD, p. 174. The Company takes exception to the RD's recommendation because it appears to have the unintended consequence of resulting in an inadequate budget for this category, one that is even lower than Staff's proposed budget.[41] As a result, the RD's recommendation should be rejected for the same reasons that the RD rejected Staff's methodology – it does not account for updated known cost increases.

The problem with the RD's recommendation is two-fold. First, inflating 2022 actuals for the leak prone pipe ("LPP") replacement program as recommended by the RD does not accurately reflect the unit cost increases the Company is actually experiencing within this program. This is highlighted by comparing the RD's proposed budget for 2024 to the 2023

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40 The Company assumes for purposes of the RD's recommendation that the latest known actuals are from 2022, which are the latest actuals submitted into evidence in these proceedings.

41 Specifically, under a strict interpretation of the RD, basing the budget for Distribution Improvements solely on latest 2022 actual costs of $37.5 million, adjusted for inflation, would produce a budget of $39.7 million in 2024 and $40.6 million in 2025. These budgets are woefully short of the Company's proposed budgets of $51.6 million in 2024 and $56.4 million in 2025, and significantly lower than Staff's recommended capital budgets of $46.3 million for 2024 and $48.7 million for 2025.

actuals.[42] In 2023, the Company spent approximately $46.2 million on Distribution Improvement projects (which again primarily consisted of LPP removal)[43] – approximately $3.0 million more than the RD's recommended budget for 2024 and just slightly more than the RD's recommended budget for 2025. Indeed, the 2023 actuals were approximately 23% higher than the 2022 actuals of $37.5 million, further demonstrating that inflating off of 2022 actuals will not produce accurate budget results.

Second, because the vast majority of the Company's 2022 actual spend for Distribution Improvements was related to LPP replacement, the latest known actuals do not reflect costs for the newly proposed programs within the Distribution Improvements category. These programs include the Compression Coupling Neighborhoods, Transmission Service to Distribution program, the Leak Prone Pipe Services, and the River/Creek Crossing Reinforcements. Given that there are no 2022 actual costs for these programs to inflate nor a redistribution of funding contemplated for the LPP replacement program, the RD could be interpreted as providing no funding for these projects. Given that Staff did not recommend denying the Company cost recovery for these programs, the Company does not believe it was the RD's intent to starve these programs from funding.[44]

Due to these infirmities with the RD's recommendation, the Commission should reverse the RD and adopt the Company's proposed budget because it is the only budget with record support that will allow the Company to fully carry out its important Distribution Improvements

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42 The Company replaced approximately 15 miles of LPP in 2023 and is proposing to replace the same amount in 2024.

43 Cases 20-E-0428 et al., Quarterly Capital Expenditure Variance Reporting (Q4 2023) (Feb. 14, 2024). The costs presented in this filing for the Distribution Improvements category primarily consist of LPP replacement projects as the new projects proposed for this category were not experienced in 2023.

44 In fact, Staff and the Company agree that the budget for the River/Creek Crossing Reinforcements should be $500,000 and it appears the intent of the RD is to adopt this position. RD, p. 173, fn. 631.

projects. If the Company's recommended budget is not adopted, the RD's calculation for the Distribution Improvements category should be updated to provide funding for the new programs within this category, which would result in a Distribution Improvement budget of $45.4 million in 2024 and $51.6 million in 2025.[45]

C. Common Capital

The Company takes exception to the RD's recommendation to utilize a blanket 8% contingency factor with respect to Training Academy and Other Facilities, as proposed by Staff. The RD's recommendation is in error given the RD's concession that the record "supports the use of different contingency percentages based on the available information that impacts the accuracy of the cost estimates." RD, p. 186.

As the Company explained in testimony, different contingency factors apply to different projects depending on how far along the project is in the design phase. For example, projects in the definitive estimate phase would receive an 8% contingency factor while projects in the conceptual estimate phase receive a 20% contingency factor to reflect the increased risk associated with a project in the earlier stages of planning. Tr. 131. The adoption of Staff's 8% contingency adjustment for all projects ignores the record evidence that establishes the need for differentiation among projects due to the greater uncertainty associated with projects in earlier planning stages. The RD's recommendation is based on nothing more than mere speculation – that given the passage of time since the initial filing, projects then in the early planning stages have progressed to later stages. Such speculation, of course, is not evidence and cannot be

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45 These figures utilize the latest information that was made available to Staff for the new programs, which was used by Staff in development of its recommendations.

adopted because the Commission's determinations must be supported by substantial evidence.[46] The RD's recommendation is therefore in error and should be reversed in favor of the Company's recommendation to apply a 20% contingency factor to the Transportation Building - EC, Butler Building Rebuild, and Ellenville Office Renovation projects, which is supported by the evidentiary record.

VII. CLCPA COMPLIANCE

C. CLCPA Deferral Mechanism

The Company takes exception to the RD's denial of the Company's proposed CLCPA deferral. In denying the deferral mechanism, the RD erred in finding that "[t]o the extent [the Company] incurs such additional costs that do not meet the materiality requirements to support a deferral petition, those costs are appropriately treated as the Company's cost of doing business as a regulated entity." RD, pp. 239-240. The fact that costs related to implementation or compliance with CLCPA-related requirements are a utility "cost of doing business" in New York is exactly why the CLCPA deferral should granted. The Commission has long determined that utilities are entitled to recover from customers the necessary costs of doing business.[47] Denial of the proposed CLCPA deferral mechanism will potentially deny the Company the ability to recover "costs of doing business," in contravention of New York State law, because: 1) incremental costs related to implementing CLCPA-related requirements may be incurred in the

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[46] See 300 Gramatan Ave. Associates v. State Div. of Human Rights, 45 N.Y.2d 176, 180 (1978) ("Marked by its substance - its solid nature and ability to inspire confidence, substantial evidence does not rise from bare surmise, conjecture, speculation or rumor."); see also, Pell v. Bd. of Educ., 34 N.Y.2d 222 (1974).

[47] See e.g., Case 29069 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service, Opinion No. 86-6 at 137 (Mar. 12, 1986) ("Finally, DOL has not shown that the costs incurred by the company in defending environmental litigation are other than ordinary and necessary costs of doing business which the company is entitled to recover from ratepayers.").

Rate Year (Tr. 2788-2789); and 2) it is unclear whether such costs will meet the Commission's three-prong test for deferral treatment or be addressed in a generic proceeding.

VIII. CLIMATE LEADERSHIP AND SUSTAINABILITY INITIATIVES

G. Climate Resilience Surcharge

The Company does not except to the RD's recommendation regarding denial of the Climate Resilience Surcharge, but notes that it will defer costs associated with the Company's Climate Change Vulnerability Study and Climate Change Resilience Plan in accordance with Public Service Law § 66(29) and Case 22-E-0222.

IX. RATE OF RETURN / FINANCIAL ISSUES

A. Absent Relief a Credit Downgrade Looms

The Company's Reply Brief (page 60) stated clearly and concisely that:

> No discussion of the appropriate elements of the rate of return – neither return on equity ("ROE"), capital structure, nor debt cost rates – can proceed without squarely addressing the essential fact that, by its own admission, Staff's case will produce credit metrics that lie well below the level that could produce a credit downgrade and thereby impair Central Hudson's ability to attract capital on reasonable terms.[48]

Despite its thorough and exhaustive treatment of nearly every other issue in contention, the RD's silence on this important financial integrity issue requires the Company to except. Given the immense financial implications to Central Hudson,[49] and, indeed, to other utilities in New York that must compete for capital, this issue simply cannot be ignored.

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[48] The Company's Reply Brief went on to explain that "no matter how deftly Staff's Initial Brief tries to argue otherwise, the fact remains that Staff's case would produce a Moody's CFO Pre-WC/Debt metric that is 170 basis points below even what Staff claims is Moody's downgrade threshold at 11% and, as will be demonstrated, is even much further below the threshold Moody's actually states would trigger a downgrade." Company Reply Brief, pp. 60-61.

[49] For example, the Company's Finance Panel noted that when Central Hudson went to market in March 2023 for $90 million of long-term debt, the maturities priced with spreads of 170, 180 and 190 basis points ("BPs"), respectively. In contrast, in 2018 when the Company was rated the equivalent of "A-", it issued 15-year bonds with a spread of 105 BPs. Tr. 945. The higher spread, which is directly correlated to the Company's credit

Staff's own exhibit, Moody's May 16, 2023 Credit Analysis (Exhibit 266 (ASH-7)), makes Moody's position crystal clear that Central Hudson's ratings could be downgraded if CFO Pre-WC/Debt is sustained below 14%. Exhibit 272 (ASH-13) indicates Staff's view that its proposed ROE of 9.20% and a 48% equity ratio would produce a CFO Pre-WC to debt metric of only 9.3%. The RD, albeit while more reasonable in certain aspects than Staff's position, ultimately recommends Staff's proposed equity ratio and ROE, which continues to pose the potential for further deterioration of the Company's credit metrics. RD, pp. 266, 278. Consequently, a downgrade by Moody's and resulting higher borrowing costs remain a possibility absent remediation. This is especially important in the face of today's high interest rates.

Given the possibility of a costly downgrade, there are only so many financial levers that can be pulled to avoid it. The Company's Finance Panel noted that the path for avoiding a downgrade begins with adoption of the Company's recommended ROE of 9.8%. Tr. 1002. The Finance Panel also explained how the Company's metrics would be improved by proper recognition of significant cash outlays including for storms and New York State mandated programs. Tr. 989-990. Cash recovery mechanisms, such as the Rate Adjustment Mechanism ("RAM"), are also credit-supportive by providing more current recovery of significant cash outlays.[50] Id. Setting an appropriate depreciation expense also provides cash flow relief for the Company and supports credit ratings. Unfortunately, however, with the singular exception of a partial recognition of a more appropriate depreciation expense (but without an appropriate

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rating, causes millions of dollars in additional interest costs that then raise costs to customers now and well into the future. Id.

50 The Company's Finance Panel explained that if cash outlays and rate allowances for storm expenses and energy efficiency program expenditures had been aligned in 2022, the Moody's credit metric would have been above the downgrade threshold of 14%. Tr. 997.

amortization of the reserve deficiency), the RD rejects the recognition of a proper level of major storm expense and denies revenue reconciliation mechanisms such as the RAM that allow for timely recovery of regulatory assets. For this reason, the Company's ROE and equity ratio are the most impactful levers remaining to fend off the possibility of a credit rating downgrade.

B. The 50% Equity Ratio Has Ample Record Support

The RD (p. 262) contends, erroneously, that:

> Central Hudson claims that a 50 percent equity ratio is necessary for it to achieve and maintain an "A" or equivalent credit rating, keeping it attractive to investors and allowing it to obtain equity readily and at the best price for customers."

That is not what Central Hudson claimed or what the record reflects. In fact, the Company's Finance Panel testified that to increase Central Hudson's credit rating by one notch to A3, a 10.8% ROE and 53% equity ratio would be needed to achieve the target rating. Tr. 962. The Finance Panel testified equally clearly that an ROE of 9.8% and equity ratio of 50% was supportive of Central Hudson's *current* ratings of BBB+ and Baa. See Tr. 955, 961.

Furthermore, an equity ratio of just 48% produces a mismatch with the proxy group. The RD's 48% equity ratio is 3.66 percentage points lower than equity ratios authorized by other jurisdictions in 2020-2022. Tr. 208. The 48% equity ratio is also inconsistent with the trend in other jurisdictions which has increased to an average equity ratio of 52.57% in 2022. Id.

The RD concedes that the Commission has approved a 50% equity ratio in the past but inaptly concludes that approval in that case was premised on the Tax Cut and Jobs Act ("TCJA"), which no longer is much of an influence on financial metrics. RD, pp. 264-265. The rating agencies, however, cited the deterioration of cash flow metrics, thin equity layer, and uncertain regulatory supportiveness as key factors to the ratings actions (Tr. 942-943) – all things that remain concerns under the ROE and equity ratios proposed by the RD.[51]

Finally, the RD found "highly persuasive" Staff's assertion that other utilities were able to access capital with a 48% equity ratio. RD, p. 266. Notwithstanding what other utilities are facing, on this record and for the Company, absent relief, including the adoption of a thicker equity ratio, the possibility of a downgrade of Central Hudson's credit rating cannot be discounted under the metrics produced.[52]

C. The ROE Recommended in the RD Is Understated and Unrepresentative of Current Capital Conditions

1. The Record Demonstrates that Precedent Should Not Control

In deriving the ROE to be applied in this case, the RD relies almost entirely on the "yardstick" of conformity with Commission precedent. It states:

> [M]arket conditions and the current financial profile of the Company…were not significant enough…to warrant a departure from the Commission's express methodological precedent…We use Staff's recommended 9.2 percent ROE in our attached revenue requirement calculation.

RD, p. 278. To the contrary, the record and the end result warrant a course correction.

Staff's Discounted Cash Flow ("DCF") result of 8.61%, together with its Capital Asset Pricing Model ("CAPM") results, weighted 2/3 DCF and 1/3 CAPM, produce Staff's 9.20% ROE. Given that the Commission itself has not determined an ROE to be as low as 8.61% in recent memory, one must question the underpinnings of the Commission's own model. The RD

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51 The RD is wrong that the TCJA no longer affects cash flow, as made clear in Staff's response to CH to DPS (042), included in Exhibit 200 (FP-1R). The TCJA still affects cash flow. Tr. 959. More important, however, if, as Staff Witness Hale conceded, "other, more significant factors" have replaced the TCJA (Tr. 2373), then there is even more of a reason to increase the equity ratio now, not less.

52 The RD's argument devolves into a non sequitur. The point is not at what terms the Company can market its securities at its current ratings; rather the issue is what would happen to the Company's financial integrity and costs if it were to be downgraded by one or more of the credit rating agencies resulting from the RD's recommended outcome in these rate cases.

fails to reconcile the disparate results of Staff's DCF analysis and CAPM analysis which provide estimates that are separated by 172 basis points. In fact, given that Staff's CAPM result of 10.33% is closer to the 10.00% ROE awarded to Central Hudson on June 16, 2010, when interest rates were lower than those seen today, it is clear that the DCF analysis is an outlier.[53]

Indeed, the record indicates several instances where Staff's DCF model rested on faulty assumptions. For example, the RD avers that "the use of earnings growth rates is unnecessary given that the best evidence is the actual dividend growth rates and forecasts that are readily available." RD, p. 271. In contrast, the Company's witness, Mr. Nowak, properly used a consensus of analysts' Earnings Per Share ("EPS") growth rates for the proxy group companies as the near-term growth rate, and an estimate of growth in the overall economy for the long-term growth rate. Tr. 236. This mitigates the uncertainty associated with forecasting individual companies' growth rates over very long-time horizons. Staff, on the other hand, used dividend growth projections from only a single source (i.e., Value Line).[54] Id. Dividend payments and capital appreciation, however, are both a function of earnings. Tr. 237. Indeed, without earnings, dividends cannot be sustained; an obvious fact is confirmed by a rich resource of authors in the financial literature. Tr. 238-240.

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[53] See infra fn. 57. Not only does Staff place the majority of its weight on the DCF analysis, Staff offers no explanation in its consideration of market conditions as to why the DCF model diverges from the CAPM, and other observable benchmarks that are relevant to the ROE analysis. As a result, the underlying assumptions of the DCF model must be considered and the end result must be assessed in the context of current market conditions.

[54] The RD points to the quality control review Value Line employs in an attempt to assuage concerns about relying extensively on a single source. The RD, however, in no way addresses the bias that can result from relying on a single source, rather than consensus estimates which represent multiple analysts from multiple firms informing investors. While the RD speaks to the long-standing nature of the Commission's analysis, it fails to consider the extent to which the investment community relies on Value Line today, as compared to decades ago when consensus estimates were not as widely available.

Another example is the Company's proper use of the XIRR function to determine dividend growth. Although the RD explicitly ignored this issue altogether, Mr. Nowak explained that the XIRR is a superior tool because every utility in his, and Staff's proxy group, pays quarterly dividends, not dividends at the end of the year. Tr. 248.[55] Money has a time value, but the Commission's methodology assumes that investors will wait a full year for a dividend payment. Merely applying the more precise – and more realistic – XIRR function could increase Staff's DCF result from 8.61% to 8.78% and increase its overall ROE estimate from 9.20% to 9.30%.

Finally, the weighting of the DCF and CAPM has been addressed several times by the Commission. The record in this case, however, makes it abundantly clear that there is no reason to refrain from finally weighing the two methods equally, as the Recommended Decision in the Generic Finance Proceeding assumed would eventually occur.[56] The RD's reliance on 9.20% is unduly influenced by a flawed DCF estimate of 8.61%. ROEs authorized by other regulatory agencies for electric and natural gas distribution utilities since 2021 have averaged 9.59% over a period in which interest rates reached historical lows. As such, ROE estimates that are nearly 100 basis points below this highly relevant benchmark warrant scrutiny. The record is replete with observations that demonstrate that Staff's DCF result is incompatible with investors'

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[55] The Company is aware of a 2009 Con Edison decision where the Commission declined to adopt the quarterly model. In that decision, the Commission rejected the ALJs' adoption of the finding: "[a]ny extra return to be achieved on account of quarterly dividend reinvestment will be achieved by those who actually reinvest all their dividends in the Company's stock [and a]ny additional allowance would be duplicative for those who actually reinvest dividends and unnecessarily generous to those who do not." Case 08-E-0539 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Setting Electric Rates at 126-127 (Apr. 24, 2009). This, too, ignores the time value of money. Whether a dividend received is reinvested back into the company or invested into another instrument does not change the value of the money invested at the time. For all these reasons, the XIRR function that Mr. Nowak used is superior because it reflects the value of the dividend received at the time.

[56] Case 91-M-0509 - Proceeding on Motion of the Commission to Consider Financial and Regulatory Policies for New York State Utilities, Recommended Decision (July 19, 1994), 1994 N.Y. PUC LEXIS 141 at *60.

required returns in the current capital market environment. Staff's CAPM estimate of 10.33% is within a single basis point of the Company's updated DCF result of 10.34%. Given that the Company was awarded a 10.00% ROE in 2010, when interest rates were lower than recent levels, it is reasonable to place less weight on estimates that are substantially removed from relevant benchmarks. Doing so would potentially allow New York's ROEs to no longer be among the lowest granted in the United States.

2. The ROE Recommended in the RD Fails the Ultimate Test of Hope Natural Gas

Based on precedent alone, the RD at page 278 also ignores the Supreme Court's finding that in determining an appropriate equity return, it is "the result reached not the method employed which is controlling."[57] The mechanistic application of the formulae embraced by the Commission produces an ROE that is not "commensurate with returns on investments in other enterprises having corresponding risks" nor is it "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[58]

In the equally seminal Bluefield case, the Supreme Court held:

> The return should be reasonably sufficient…to maintain and support [a utility's] credit and enable it to raise the money necessary for the proper discharge of its public duties…[59]

Because the metrics produced by the RD's 9.20% ROE are inconsistent with the metrics required to maintain Central Hudson's current bond rating, the Bluefield and Hope standards are transgressed.

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57 Fed. Power Com. v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944).

58 Id. at 603.

59 Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n., 262 U.S. 679, 693 (1923).

Furthermore, the RD's 9.20% return also fails the additional Bluefield test of temporal and geographical comparability. In terms of comparability, the record indicates that ROEs authorized by other regulatory agencies for electric and natural gas distribution utilities since 2021 have averaged 9.59%.[60] Tr. 218.

In terms of temporal consistency, the Commission's methodology is also deficient. The record indicates that the Company was awarded a 10.00% ROE on June 18, 2010 at a time when interest rates were lower than today.[61] This highlights the fact that, rather than "providing consistency and predictability," as the RD claims, the mechanistic approach used in New York over the last decade has produced inconsistent and unreliable ROEs.[62] The Commission's reliance on determinations made over 30 years ago in the Generic Finance Proceeding are out of step with the current regulatory landscape, financial circumstances, and investor expectations.

Given the above, the path forward to maintaining Central Hudson's financial integrity is clear: an equity ratio of 50% and an ROE at least near the national average ROE for electric and gas utilities. Doing so will provide the financial strength to maintain the Company's existing ratings, which are, as mentioned, below the "A" bond rating that the Commission has previously found to be appropriate. To do otherwise would jeopardize Central Hudson's financial integrity

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60 Despite historically low interest rates over a significant part of that period, only three of the 112 electric and gas cases during that time were as low as the RD's recommendation of 9.20%. Nor is there any basis to assert that New York regulation merits lower ROEs. The record is clear that Central Hudson has comparable regulatory protection to the proxy group companies, as New York's ranking from RRA as "Average/2" confirms that assessment. Tr. 261-262. Central Hudson's exposure to negative revenue adjustments ("NRA") places Central Hudson at greater risk than proxy companies on average. Id.

61 Cases 09-E-0588 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service, Order Establishing Rate Plan at 15 (Jun. 18, 2010). The 30-year yield on June 16, 2010 was 4.18%. As of October 31, 2023, the 30-year yield averaged 5.04%, approximately 86 basis points higher, highlighting the importance of considering the effect of changes to capital market conditions in an authorized ROE. Tr. 217.

62 This is all the more evident given that in 2010 the Commission might credibly claim that New York regulation was producing lower risk due to progressive ratemaking methods. This potential advantage has disappeared. New York regulation confers no regulatory advantages and, to the contrary, imposes additional regulatory risk. Tr. 258-262.

and credit at a time when interest rates are elevated and the requirements of the CLCPA and other state initiatives mandate more, not less investment, thereby putting in peril important state policy initiatives and the credit of the New York utility industry generally.

X. COMMISSION AUTHORITY TO IMPOSE PERFORMANCE METRICS

The RD states that "Central Hudson asserts that a litigated outcome prevents it from agreeing to what it believes is an achievable and acceptable performance metric program on a revenue requirement basis." RD, p. 281. On one hand, the RD recognizes that, as part of the Electric Capital Stipulation (Exhibit 516), Central Hudson has, in fact, agreed that: "[t]he Company's current SAIFI and CAIDI targets and NRAs continue through 2024, and the targets will remain in effect until modified by Commission order [and] the Company and Staff agreed to continue the same SAIFI and CAIDI targets and NRAs for 2025." RD, p. 290. On the other hand, while asserting the Commission's authority to impose such standards through NRAs (RD, pp. 283-286), the RD acknowledges that there exists precedent for no imposition of any NRAs for customer service and gas safety.[63] RD, p. 287. The RD, perhaps unwittingly, has presented the Company with a conundrum regarding the gas safety and customer service metrics. Consequently, although the RD appears to present a reasonable compromise with which the Company arguably could live with – a limited continuation of the customer service metrics agreed to as part of the 2021 Rate Plan – it also posits an alternative path, to which Central Hudson cannot agree, namely: the RD's statement that, "[t]hus, if the Commission chooses not to

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63 The RD cites to the 2017 National Fuel Order where the Commission found that it was declining the Judge's recommendation in that instance to impose such metrics because the record amply demonstrated that NFG had demonstrated exceptional performance by surpassing its performance program from its previous rate plan. RD, p. 287. This is the same situation that obtains here with respect to the gas safety metrics, where Central Hudson has both exceeded its historical performance as well as the statewide average performance on a consistent basis.

continue the performance metrics established in the 2021 Rate Order, we believe that imposition of the following minimum targets, NRAs and PRAs would not be unreasonable." RD, p. 303.

This is the alternative to which the Company excepts and why it continues to assert that the Commission is without power to order the performance metrics to be imposed, both generally, as a matter of law, and specifically under the facts and circumstances adduced by this evidentiary record. Notably, Central Hudson would prefer to moot this entire controversy by signaling its partial acceptance of the compromise wrought by the RD: that is, to continue the Customer Service programs and metrics in place under the 2021 Rate Plan but hold in abeyance the Gas Safety performance metrics based on the National Fuel precedent identified by the RD. In the event, however, that the ALJs and the Commission refuse that option, Central Hudson excepts and continues to assert that the Commission lacks the power to impose the penalties proposed by Staff and other parties or those adopted by the RD as alternatives to its compromise position.

The Company explained in its Initial and Reply Briefs the reasons why the Commission lacks the power to impose penalties that are not explicitly enumerated in the Public Service Law. The RD posits, however, that "the authority to determine specific and targeted utility performance programs based on a combination of the individual characteristics of a utility's infrastructure and customer base, together with a utility's historic performance, is necessarily incidental to the power expressly granted in PSL §65(1)." RD, p. 284. Under the circumstances of this case, the Company respectfully posits that the RD is mistaken.

Although Staff's witnesses conceded, for example, that neither the Public Service Law nor the Commission's regulations set forth a minimum level of customer service (Tr. 4510), the

RD points to Hurley Water[64] as support for rate of return penalties related to "poor service." RD, p. 286. Hurley Water, however, involved a temporary rate of return based on a record of service problems that would reset once service improved. It did not provide for a series of after-the-fact penalties imposed retroactively based on arbitrary and differing standards. The RD's reliance on Hurley Water thus fails to address or refute the Company's arguments that the NRAs transgress on both the enumerated powers of the Commission and its inability to set rates retroactively.

The RD further states "[w]e agree with Central Hudson that the state's utilities are entitled to equal protection under the law" but then asserts without basis that "specifically directed performance programs do not violate equal protection principles simply because Commission established goals differ among utilities." RD, p. 284. Although that may be arguably true as a general proposition, the RD fails to show that, *in this case*, there is any evidence to support a claim that a basis exists to apply different customer service and gas safety standards to the Company than to other utilities.[65] In fact, the very cases cited by the RD establish that Commission decisions must have record support and a rational basis.[66] Furthermore, equal protection considerations aside, treating similarly situated entities differently,

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64 Hurley Water Co. v. Pub. Serv. Comm'n, 87 A.D.2d 678, 679 (3d Dep't 1982).

65 In fact, the Weissman case, which is relied on by the RD for the proposition that "distinctions based on geographical areas are not, in and of themselves, violative of the Fourteenth Amendment," also carefully points out that "the classification is neither capricious nor arbitrary [if it] rests upon some reasonable consideration of difference or Policy." RD at 284-285, citing Weissman v. Evans, 56 N.Y.2d 458, 465 (1982). The problem here, one the RD seems to have overlooked, is that the record in this case contains no evidence that would justify different treatment of utilities for gas safety and customer service goals. Staff conceded, however, that for PSC complaint rates and call answer rates, the targets vary among utilities. Tr. 4500, 4505.

66 Respondent's determinations may be set aside only where they are without any rational basis or reasonable support in the record (see Matter of Abrams v. Pub. Serv. Comm'n., 67 N.Y.2d 205, 218). See also Hurley Water Co. v. Pub. Serv. Comm'n., 122 A.D.2d 410, 410-411 (3d Dept. 1986) ("The commission's determination, however, may only be set aside when it is without any rational basis or without any reasonable support in the record."); Matter of New York State Council of Retail Merchants v Public Serv. Comm., 45 N.Y.2d 661, 671 (1978); Spring Val. Water Co. v Pub. Serv. Comm'n., 71 A.D.2d 55, 56-57 (3d Dept. 1979); Hurley Water Co. v. Public Service Comm'n, 87 A.D.2d 678, 679 (3d Dept 1982).

without an explanation by the administrative agency, is inherently arbitrary and capricious[67] and using different standards for similarly situated electric and gas companies is inherently irrational.[68] Although the RD claims that "[v]ery significant differences exist between the state's utilities that create differing expectations for adequate service by each utility's customer base, Department of Public Service Staff, and the Commission" (RD, p. 285), one may search the record in vain for any such evidence.

The RD contends that "[f]or example, geographical differences between service regions present varying conditions under which what may be considered an adequate restoration response time in one location, may be wholly inadequate in another." RD, p. 285. The problem, again, is that there is absolutely no record evidence to warrant or explain why a geographical difference between or among utilities would warrant the imposition of different metrics.[69]

Finally, the RD contends that a utility's "historic performance" is a valid reason to vary performance metrics and NRAs among the utilities. RD, p. 284. To the contrary, a utility's historic performance may or may not be a valid reason for improvement but it is hardly a reason to discriminate among utilities and, as was pointed out on numerous occasions, results in Central Hudson being penalized for excellent gas safety performance while a lesser performing utility escapes penalties altogether because its performance – albeit still far below its better performing peer – manages to eke out a better performance than its previous record. Rather than warranting

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67 In re Charles A. Field Delivery Serv., 66 N.Y.2d 516, 518-519 (1985).

68 Mtr. of Buffalo Civic Auto Ramps, Inc. v. Serio, 21 A.D.3d 722, 725 (4th Dep't. 2005) ("Where two cases are so similar as to require the same treatment, to treat them differently would be evidence that the determination should be considered arbitrary and capricious.").

69 The one metric – emergency response time – where geographical differences might warrant disparities in performance metrics (because utilities have wide disparities in distances in their respective service territories), has uniform standards of statewide applicability. See Exhibit 222 (GSP-2R), Sheet 14. Given the complete absence in this record of any evidence that would account for disparities in the NRAs applied to utilities and the evidence of such disparities (Exhibit 223 (GSP-3R)) in the metrics and NRAs applied by Staff to different utilities in the state, there exists no rational basis to impose the NRAs and metrics advocated by Staff.

discrimination, such a result – rewarding lesser performers while penalizing high performers – is entirely arbitrary and capricious.

For all of the above reasons, in this case and on this record, there is no legal or evidentiary basis to impose the customer service and gas safety standards advocated by Staff.[70] As noted, Central Hudson is willing to accept a continuation of the customer service performance standards adopted in the 2021 Rate Plan to be applicable during the Rate Year in this case. But if that option is not available, the Company excepts and asserts that the Commission lacks the power – both generally and particularly on this record – to impose any such NRAs and performance metrics.

XII. GAS SAFETY

B. Leak Management

As discussed above, it is the Company's position that gas safety performance metrics should be held in abeyance based on the precedent in the 2017 National Fuel Order. Should the Commission, however, decide to impose NRAs in these one-year litigated proceedings, the Company agrees with the RD that the 2021 Rate Plan gas safety performance metrics should continue in the Rate Year. In the event the Commission disagrees with that recommendation, the Company notes that the RD recommends modifying the leak management targets and associated NRAs/PRAs as follows:

Number of leaks at Year-End	(NRA)/PRA (BPs)
≥68	(15)
≥60 - ≤68	(6)
≥50 - ≤59	0

70 The RD points to the 2017 National Fuel Order where the PSC declined to impose customer service and gas safety NRAs but claims that the record here is not sufficiently similar to warrant a like result. Central Hudson disagrees with respect to gas safety. The RD concedes that the Company "has exceeded certain performance metrics under the 2021 Rate Plan" and there is no evidence that the excellent performance by Central Hudson is fundamentally different from the performance of National Fuel that merited the absence of NRAs for that company.

≥47 - ≤49	2
≥46 - ≤48	4
≤45	6

If the Commission adopts this recommendation, the Company requests the Commission clarify what appears to be a transposition error regarding the four and six BP PRA tiers. Specifically, the Company submits that the four BP PRA tier should be ≥45 – ≤46 leaks and the six BP PRA tier should be ≤44 leaks.

F. Leak Prone Services Replacement Program Initiatives

The RD correctly recognizes that the Company and Staff are both supportive of the Company's proposal to implement a new Leak Prone Services Replacement ("LPSR") Program and that the only disagreement between the parties is over the appropriate performance targets and associated PRAs for the program. RD, pp. 314-315. The RD, however, appears to suggest that the new LPSR Program should only be funded if "if the Commission chooses to employ NRAs or PRAs in this litigated rate case." RD, p. 315. If that is indeed the RD's recommendation, the Company takes exception to it.

As the RD acknowledges, the "program is intended to proactively address services located in close proximity to a house before leaks cause hazardous situations" and LPP removal has "public safety benefits and GHG-mitigating effects." RD, pp. 314, 316. Given the safety and environmental benefits of the LPSR Program, the program should be funded regardless of whether the Commission adopts NRAs or PRAs in this proceeding.

Should the Commission determine PRAs are appropriate for this program, the Company also takes exception with the RD's recommendation to adopt the associated targets and PRAs recommended by Staff. The RD erred in finding that the Company had not met its burden of proof that its proposed targets and PRAs are reasonable.

The RD's findings with respect to EAM targets apply equally to PRA targets:

> However, while we agree with Staff that EAM targets should be a stretch, we do not believe that setting the targets at the elevated levels that Staff recommends will have the effect of motivating the Company to achieve those goals. Rather, if the targets are too high and perceived as unachievable, the Company may elect to forego any additional effort to attain those goals.

RD, p. 446. In other words, for a PRA incentive mechanism to be effective, the applicable targets must be achievable from a cost-benefit analysis perspective. In setting its proposed targets, Staff conceded that it does not take costs into consideration. Tr. 2772. There is also nothing in the record that establishes that the Company would be able to achieve a PRA under Staff's recommended targets, nor the requisite level of funding needed for the Company to remove at least 124 services before it is eligible for a PRA. On the other hand, the Company's proposed targets, which would allow the Company to earn a PRA upon removing 51 or more leak prone services are patently reasonable and achievable given that the Company currently replaces an average of 39 leak prone services a year through the leak management program.

For these reasons, the Commission should fund the LPSR Program and adopt the targets and associated PRAs proposed by the Company.

XIII. CUSTOMER SERVICE

If the Commission does not adopt the RD's recommendation to apply the 2021 Rate Plan Customer Service Performance Indicator ("CSPI") targets and associated NRAs to the Rate Year, which as noted above, Central Hudson is willing to accept, the Company takes exception to the RD's treatment of the PSC Complaint Rate, Residential Customer Satisfaction, and Call Answer Rate metrics as indicated below.

1. PSC Complaint Rate

Central Hudson proposed to maintain the PSC Complaint Rate metric and its existing targets from the 2021 Rate Plan but to modify the metric to exclude complaints associated with commodity prices because such prices are outside its control. Moreover, doing so would "increase alignment across the state, as this exclusion was included in Con Edison's Joint Proposal recently approved by the Commission." RD, p. 324, citing Tr. 3012. The RD, however, recommended that the existing complaint metric be maintained without the exclusion modification requested by Central Hudson and previously granted to Con Edison. RD, p. 329.

When the PSC Complaint Rate metric was being developed it was recognized that "[c]omplaints about high bills resulting from the price of electric energy and capacity… will not be counted as complaints..."[71] For example, when Orange and Rockland Utilities, Inc. ("O&R") petitioned the Commission in 2005 to exclude high commodity supply prices from its PSC Complaint Rate metric, the Commission determined that "O&R's proposal to exclude certain complaints from the calculation of this incentive is reasonable…"[72]

The RD believes, however, that "allow[ing] Central Hudson to challenge an escalated complaint" obviates the need to exclude complaints based on high commodity cost. RD, p. 329. The ability to challenge escalated complaints related to commodity costs does not alter the fact that inclusion of such complaints in the metric inappropriately captures macroeconomic events driving commodity costs that are beyond the Company's control. The RD also questions the correlation between complaints and commodity prices. RD, pp. 329-330. Here, again, the RD

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[71] See e.g., Case 04-E-0572 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Adopting Three-Year Electric Rate Plan, Joint Proposal at 55-56 (Mar. 24, 2005).

[72] Cases 02-G-1553 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service, Order Approving Complaint Rate Targets at 6 (Aug. 26, 2005).

errs. Exhibit 184 (CEP-6R) establishes a clear correlation between complaints and commodity prices, lagged by one month, detailing the complaints that arise one month after a commodity price increase.[73] The Company's Customer Experience Panel testified that it "calculated the correlations between the four CSPI metrics SCSP proposed and the correlations between the CSPI metrics and electric and gas supply prices for the period 2018 through 2022." Tr. 3055, lines 17-19.

The RD also asserts that Central Hudson pointed to only two other utilities that have the commodity price exception in their rate plans and then erroneously states that utilities were allowed those exceptions through settlements. RD, p. 331. As noted above, high commodity price complaints have consistently been and continue to be excluded from O&R's PSC Complaint Rate NRA calculation, both via settlement and a Commission order in a litigated proceeding.[74] Moreover, given Staff's concession that Central Hudson and O&R's service territories are similarly situated (Staff Initial Brief, p. 208), there is no basis for Staff's recommended disparate treatment of Central Hudson.

Finally, the RD's assertion that the Commission's "sweeping reform" of ESCOs somehow vitiates the need to differentiate high commodity price complaints, (RD, p. 331) seems to ignore the entire restructuring of the energy industry, where electricity generation was stripped away from electric utilities. For all these reasons, commodity price complaints should be removed from the PSC Complaint metric.

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[73] Staff, in contrast, has no idea if areas with higher commodity prices had higher complaint rates. Tr. 4504.

[74] Case 10-E-0362 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, Order Establishing Rates for Electric Service at 97-98 (Jun. 17, 2011) (continuing the PSC Complaint Rate measure under the company's current rate plan, which excludes high commodity price complaints from its calculation, in a litigated one-year rate case).

3. Call Answer Rate

The targets for the Percent of Calls Answered within 30 Seconds metric should be updated to align with the Company's actual performance based on a modified Staff calculation methodology that includes customer callbacks for the period 2015 through 2019. Tr. 3047-3048. A callback is an option available to customers who wish to have a Company representative call them back rather than wait in a hold status for a customer service representative or when customers are trying to reach the Company after hours. Tr. 3047; Exhibit 352 (SCSP-1), p. 1835. When the customer chooses the callback option and the Company does in fact call the customer back within two hours, the Company undoubtedly meets the customer's expectation, which Staff agrees the Company should be striving to achieve. See Tr. 4505.

Although agreeing "with Central Hudson that there are customer experience benefits associated with the use of virtual hold and callback queue technologies and they may provide a better customer experience than if those technologies were unavailable," the RD nevertheless rejected any change to the call answer metric. RD, pp. 347-348.

Including callbacks within the Percent of Calls Answered within 30 Seconds metric ensures that the customers that choose this option will be included in the overall measurement of this metric. It also encourages rather than discourages the Company's use of automated technology, a technology that is pervasive among all companies with a customer service component (Tr. 4510) and for which the Company's customers have come to expect. The RD's rejection of the use of this proven technology should be reversed.[75]

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[75] The RD's adoption of the metrics in the 2021 Rate Plan should also be modified. In recognition of a calculation error identified by Staff, it is the Company's position that the targets for the Percent of Calls Answered within 30 Seconds metric should be updated to align with the Company's actual performance based on a modified Staff calculation methodology, which includes customer callbacks for the period 2015 through 2019 in lieu of the Company's performance utilizing the incorrect calculation for the period 2015 through 2019. Tr. 3047-3048.

H. Economic Development

The Company does not except to the RD's recommendation that the Commission deny the Company's gas economic development budget. RD, p. 403. However, in order to implement this recommendation, which results in Rate Year funding of $800,000 for electric and zero for gas, the Company will need to make an accounting change. As stated in the Company's Initial Brief, economic development costs in general are allocated based on the common allocation since the benefits of economic development accrue to all Central Hudson customers. Company's Initial Brief at 250; Tr. 3091. To reflect that this economic development funding is now electric-only, the Company will no longer be able to use the common allocation and therefore requests an accounting change to authorized it to allocate the funding 100% to electric.

J. Reporting Requirements

The RD states that the ALJs do not object to PULP's recommendation for the Company to post the attestation contemplated in the Billing Reporting Stipulation (Exhibit 514) on its website.[76] RD, p. 410. The Company excepts to this portion of the RD as it is inconsistent with the conclusion in the RD that the Billing Reporting Stipulation should be adopted and not disturbed. RD, p. 410. The adoption of PULP's recommendation would serve to undermine the resolution reached between the Company, Staff and UIU on these issues.[77] Further, the statement in the RD that posting the attestation on the website "is not unduly burdensome on the Company or its resources" is without record support. Similar to the other PULP recommendations

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This results in the following tiers for the Percent of Calls Answered within 30 Seconds metric: < 62.6%; ≤ 57.3%; and ≤ 52.0% for tiers one, two, and three, respectively. See Exhibit 186 (CEP-8R).

[76] Though the RD does not recommend adoption of PULP's recommendation, the Company frames this section as an exception.

[77] The Company notes that the Billing Reporting Stipulation is intended to be adopted as an integrated whole. Exhibit 514, pp. 5-6.

regarding publication and outreach, "there is no record developed on the costs and benefits" of PULP's recommendation. RD, p. 410. The Billing Reporting Stipulation should be approved by the Commission as an integrated whole, and PULP's recommendation should be denied.

XV. EARNINGS ADJUSTMENT MECHANISMS

The Company excepts to the RD's recommendation to disallow the Company's proposed EAMs and any associated incentive opportunities, other than those associated with the Company's proposed Disadvantaged Communities Energy Efficiency Benefits EAMs.[78] RD, pp. 430-431. The RD errs by failing to adequately consider the significant benefits provided to customers by achievement of the Company's proposed EAMs, which far outweigh the cost of any incentives the Company could potentially earn. The RD correctly states that "[p]ositive incentives can motivate the achievement of desired outcomes and can help achieve energy policy goals" and that "the Commission has broad authority to adopt EAMs in litigated rate proceedings…" RD, p. 430. However, the RD errs by concluding that EAMs are inappropriate because parties expressed concerns about rate impacts in these proceedings.[79] Id.

Achievement of the EAMs proposed by the Company will provide significant benefits to customers while also helping the state achieve its emissions reduction and clean energy goals. Minimum achievement of the Company's EAMs results in a benefit cost ratio of 2.51 and maximum achievement results in a benefit cost ratio of 2.50. Exhibit 112 (EAMP-1). The Company's portfolio would also result in significant net benefits of $468 million and $516 million for achievement of the minimum and maximum levels, respectively. Id.

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[78] While the Company does not except to the disallowance of this EAM and associated incentives, the Company does except to the recommendation to report its performance related to this EAM, as the Company is already required to report on disadvantaged communities-related investments in Case 18-M-0084.

[79] To the extent the Commission adopts the recommendations in the RD, the Company should not be required to track and report its performance on the metrics and targets. This will require the Company to expend resources related to EAM performance without any associated incentive.

Further, the Company's proposed EAMs are supportive of CLCPA goals. For example, the Solar DER Utilization EAM will require the Company to go above and beyond in expediently interconnecting solar projects, which will help the state achieve its solar targets. The RD removes the potential reward associated with exceptional performance in this area, which serves to negate the significant clean energy and customer benefits provided by achievement of this EAM. The Commission should adopt the EAMs and basis points proposed by the Company, as the record supports the associated benefits to customers and the environment.

XVI. ENERGY AFFORDABILITY PROGRAM ("EAP")

The RD supported the Company's methodology for projecting Rate Year EAP, also known as Low Income Bill Discount Program ("LIBDP" or "Program"):

> In our view, the methodology employed by Central Hudson is reasonable. It projects an increase in the total budget for the program by increasing the two percent revenues from the prior period by two percent of its requested revenue increase, used a three-year average of actual participation to project program participation, and incorporated its proposals in forecasting the average bills. By considering how the component rate changes will impact different facets of the EAP, the proposed budget is more likely to reflect actual costs.

RD, p. 455. The RD, however, then noted that the inputs the Company used were based on its initial rate requests and that the ALJs were therefore unable to adjust the budgets to reflect the RD's rate increases. RD, pp. 456-457. As a result, and because the Company is entitled to seek new rates almost immediately following the Commission's decision, the RD recommended that the EAP budgets should be set at Staff's recommended level. RD, p. 457.

The Company does not except to the RD's decision because the Company has determined that the LIBDP budgets it proposed during litigation were overstated due to a reporting error involving the LIBDP. As indicated by the Company's May 15, 2024 filing in Cases 14-M-0565 et al., Central Hudson identified a reporting error that impacted the data provided in the

Company's monthly and quarterly LIBDP reports filed in those proceedings since the third quarter of 2021. Specifically, the system report used by the Company to prepare its monthly and quarterly LIBDP reports overstated the number of customers actively enrolled in the Program.[80]

Updating the Company's methodology, which again was supported by the RD, to reflect April 2024 actual LIBDP participants[81] and the rate increases presented in RD Schedule 1 produces EAP budgets of $12.6 million for electric and $3.7 million for gas. Because these figures are substantially similar to the RD's recommended budgets of $12.7 million of electric and $3.5 million for gas, the Company does not take exception.[82]

XVII. REVENUE ALLOCATION AND RATE DESIGN

As directed by the Notice of Schedule for Filing Exceptions, the Company consulted with Staff in preparing the bill impacts presented in Appendix 3, reflective of the revenue requirements set forth in the RD.[83] Bill impacts are reflected in Appendix 3, Schedules E and F for electric and gas, respectively, for classes for which an average bill can be presented. These bill impacts are supported by the revenue allocation, inclusive of the results of the updated ECOS studies directed by the RD, as shown in Appendix 3, Schedules A and B for electric and gas, respectively, and resulting rates shown in Appendix 3, Schedules C and D. In addition, Appendix 4 sets forth similar Schedules A through G based on the updates and required corrections authorized by the RD.

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80 This issue did not affect the processing of credits to customers or reporting of actual expenditures related to the Program. The Company plans to file updated quarterly reports covering the time period from third quarter of 2021 through third quarter 2022 and monthly reports covering the time period of October 2022 through February 2024 no later than June 14, 2024.

81 April 2024 data is not subject to the identified reporting error.

82 As noted on page 457 of the RD, EAP expense is reconciled and subject to deferral accounting treatment.

83 The bill impacts reflect the RD recommendation that the Company reflect a revenue imputation of $4.4 million. However, it should be noted that the income statements attached to the RD incorrectly reflected a $3.9 million imputation.

The Forecasting and Rates Panel included a proposal to modify tariff language to reflect the Company's recovery of IEDR Phase I costs. Tr. 1856. The Company is not aware of any objection on the record to the proposed language and as such the tariff language proposed by the Company should be adopted as part of the Commission's final order.

XVIII. USE OF REGULATORY ASSETS TO MODERATE RATES

Despite noting that "neither the Company nor Staff included rate moderators in their proposed Rate Year revenue requirements" (RD, p. 540), the RD agrees with Staff that some level of rate moderation is appropriate in these single year rate cases. Notably, the RD does not make a recommendation on the amount "to be used at this juncture in the proceedings" (RD, p. 541) but simply notes that the use of one-third of the available amounts "appears reasonable as it would leave the remaining balance to be used to moderate future rate increases." RD, p. 541.

The Company excepts to the RD's conclusion that the use of regulatory liability rate moderators is appropriate in these one-year rate cases. Such moderators are more effective and often necessary for rate levelization in multi-year rate cases and are best utilized in that context. The Company also excepts to the RD's contention that use of one-third of the total regulatory net liability moderators available would be reasonable. This contention lacks record support. The sole source identified for the one-third figure appears in a footnote indicating that Staff's initial testimony included revenue requirement figures that assumed utilization of one-third of the available regulatory liabilities. RD, p. 540, fn. 2142. Reliance on a Staff assumption in its initial testimony provides no evidentiary support, particularly given the RD's express acknowledgement that Staff did not propose any specific use of regulatory liabilities as a rate moderator in Staff's final Rate Year revenue requirement figures. Id.

Moreover, the RD's statement that use of one-third of the available net regulatory liability moderators is reasonable because it leaves the remainder available for future use is overbroad. Taken to the extreme, that logic is unpersuasive as it would support the use of any percentage less than 100%. As the RD recognized, the Company's briefs highlighted that the use of significant net regulatory balances will have the impact of further weakening the Company's CFO Pre-WC/Debt metric, "posing yet another risk to the financial integrity and credit rating metrics of the Company." RD, p. 541. If the Commission elects to use available net regulatory liabilities in these one-year rate proceedings, the amount used should be less than one-third of the available net regulatory liability balances. Using a smaller percentage would allow for some current rate moderation while minimizing negative credit rating impacts and preserving the parties' and the Commission's ability to moderate customer's bill impacts in future rate cases.[84]

XIX. CONCLUSION

For the reasons expressed above, the Company's exceptions should be granted and the RD revised accordingly.

Dated: May 21, 2024

Respectfully submitted,

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[84] The Company has included updated balances for the relevant regulatory liabilities in Appendices 1 and 2 to this brief.

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations Income Statement and Rate of Return Calculation
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision							CH Exceptions				
	Recommended Decision (RD)	Adj. No.	RD Updates	Corrections	RD as Updated & Corrected	Rate Increase	Revenue Requirement	Ref.	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
Operating Revenues												
Own Territory Delivery Revenues	$ 451,583		$ -	$ -	$ 451,583	$ 73,487	$ 525,070			$ 451,583	$ 101,987	$ 553,570
Revenue Taxes	7,777		-	-	7,777	2,156	9,933			$ 7,777	2,992	10,769
Subtotal - Delivery Rates	459,360		-	-	459,360	75,643	535,003		-	459,360	104,979	564,338
Legacy Hydro Revenue	3,916	1.	-	484	4,400		4,400			$ 4,400		4,400
Other Operating Revenues	12,452		-	-	12,452	492	12,944			$ 12,452	682	13,134
Total Operating Revenues	**475,728**		**-**	**484**	**476,212**	**76,135**	**552,347**		**-**	**476,212**	**105,661**	**581,873**
Operating Expenses												
Labor	86,266	2.	310	25	86,601		86,601	A.	8,667	95,268		95,268
Executive Incentive Comp	922				922		922			922		922
Management Variable Pay	3,399				3,399		3,399			3,399		3,399
Employee Benefits	16,348	3.		447	16,795		16,795	B.	3,265	20,060		20,060
Pension Plan	(7,359)	4.	(8,445)		(15,804)		(15,804)	C.	52	(15,752)		(15,752)
Other Post Employee Benefits	(5,817)	5.	(205)		(6,022)		(6,022)	D.	4	(6,018)		(6,018)
Employee Training, Safety & Education	2,162				2,162		2,162	E.	123	2,285		2,285
Production Maintenance	247				247		247			247		247
Right of Way Maintenance Transmission	3,595				3,595		3,595			3,595		3,595
Right of Way Maintenance - Distribution	26,252				26,252		26,252			26,252		26,252
Stray Voltage Testing	764				764		764			764		764
System Engineering & Compliance	218				218		218			218		218
Substation Testing & Maintenance	642				642		642			642		642
Transmission Repairs & Maintenance	1,266				1,266		1,266			1,266		1,266
Distribution Repairs & Maintenance	5,951				5,951		5,951			5,951		5,951
Transformer Installations & Removals	(607)				(607)		(607)			(607)		(607)
Informational & Institutional Advertising	71				71		71			71		71
Meter Installations, Removals & Maintenance	(951)				(951)		(951)			(951)		(951)
Research & Development	3,725				3,725		3,725			3,725		3,725
Economic Development	800				800		800			800		800
Meter Reading, Collections & Call Volume Overflow	5,723				5,723		5,723			5,723		5,723
Bill Print	777				777		777			777		777
Postage	1,675				1,675		1,675			1,675		1,675
Payment by Credit/Debit Card	1,276				1,276		1,276			1,276		1,276
Low Income Program	12,704				12,704		12,704			12,704		12,704
Uncollectible Accounts	3,730				3,730		3,730			3,730	-	3,730
Regulatory Commission General Assessment	2,693				2,693		2,693	F.	324	3,017		3,017
Environmental SIR Costs	789				789		789			789		789
Environmental All Other	201				201		201			201		201
Information Technology	15,897				15,897		15,897			15,897		15,897
Telephone	2,047				2,047		2,047			2,047		2,047
Rental Agreements	2,387				2,387		2,387			2,387		2,387
Security of Infrastructure	3,694				3,694		3,694			3,694		3,694
Maintenance of Buildings & Grounds	2,763				2,763		2,763			2,763		2,763
Major Storm Reserve	10,758				10,758		10,758	G.	4,064	14,822		14,822
Major Storm Amortization	4,726	6.	1,265		5,991		5,991			5,991		5,991
Non Major Storm Restoration	7,634	7.	(414)		7,220		7,220			7,220		7,220
Materials & Supplies	2,999				2,999		2,999			2,999		2,999
Stores Clearing to Expense	287				287		287			287		287
Transportation - Depreciation	3,036	8.		46	3,082		3,082	H.	(82)	3,000		3,000
Transportation - Fuel	1,238				1,238		1,238			1,238		1,238
Transportation All Other	1,674				1,674		1,674			1,674		1,674
Rate Case Expenses	576				576		576			576		576
Legal Services	1,603				1,603		1,603			1,603		1,603
Consulting & Professional Services	3,474	9.	87		3,561		3,561	I.	120	3,681		3,681
Miscellaneous General Expenses	5,357				5,357		5,357	J.	80	5,437		5,437
Injuries & Damages	5,518				5,518		5,518	K.	36	5,554		5,554
Other Operating Insurance	1,246				1,246		1,246			1,246		1,246
Office Supplies	1,209				1,209		1,209			1,209		1,209
Management & Operational Audit Costs	129				129		129			129		129
Management & Operational Audit Savings	-				-		-			-		-
Energy Efficiency	6,569	10.	(939)		5,630		5,630			5,630		5,630
Heat Pump Program	13,996				13,996		13,996			13,996		13,996
Amortization of EE/Heat Pump Assets	1,875				1,875		1,875			1,875		1,875
Electric Vehicle Program	-				-		-			-		-
Expenses Allocated to Affiliates	(1)				(1)		(1)			(1)		(1)
Miscellaneous Charges	947				947		947	L.	66	1,013		1,013
Amortization of Unprotected Asset (TCJA)	1,998				1,998		1,998			1,998		1,998
Productivity Imputation	(1,131)				(1,131)		(1,131)	M.	93	(1,038)		(1,038)
Recovery/Refund of Rate Change Timing	-				-		-			-		-
Amortization of Depreciation Reserve Adjustment	479	11.		385	864		864	N.	870	1,734		1,734
Inflation Reduction	(117)				(117)		(117)			(117)		(117)
Total Operating Expenses	**270,330**		**(8,341)**	**903**	**262,892**	**-**	**262,892**		**17,682**	**280,574**	**-**	**280,574**
Other Deductions												
Property Taxes	42,966	12.	(1,409)		41,557		41,557			41,557		41,557
Revenue Taxes	7,777				7,777	2,156	9,933			7,777	2,992	10,769
Payroll Taxes	6,217	13.	2		6,219		6,219	O.	599	6,818		6,818
Other Taxes	3,581				3,581		3,581	P.	241	3,822		3,822
Depreciation	76,540	14.		2,423	78,963		78,963	Q.	797	79,760		79,760
Total Other Deductions	**137,081**		**(1,407)**	**2,423**	**138,097**	**2,156**	**140,253**		**1,636**	**139,734**	**2,992**	**142,726**
Income Taxes												
Federal Income Taxes	3,585	15.	1,921	(620)	4,886	14,526	19,412	R.	(3,419)	1,467	20,160	21,625
State Income Taxes	3,053	15.	694	(205)	3,542	4,809	8,351	R.	(1,132)	2,410	6,673	9,083
Total Income Taxes	**6,638**		**2,615**	**(826)**	**8,427**	**19,335**	**27,762**		**(4,551)**	**3,877**	**26,833**	**30,708**
Total Operating Revenue Deductions	**414,049**		**(7,133)**	**2,500**	**409,416**	**21,491**	**430,907**		**14,768**	**424,185**	**29,825**	**454,008**
Net Operating Income	**$ 61,678**		**$ 7,133**	**$ (2,016)**	**$ 66,795**	**$ 54,644**	**$ 121,439**		**$ (14,768)**	**$ 52,027**	**$ 75,836**	**$ 127,865**
Rate Base	**$ 1,747,500**		**$ 26,118**	**$ 14,895**	**$ 1,788,513**	**$ -**	**$ 1,788,513**		**$ (5,198)**	**$ 1,783,316**	**$ -**	**$ 1,783,316**
Rate of Return	**3.53%**						**6.79%**					**7.17%**

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations Federal Income Tax
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision						CH Exceptions			
	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	Impact of Rate Increase	Revenue Requirement	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
Operating Income Before FIT, SIT, Interest	$ 68,316	$ 9,748	$ (2,842)	$ 75,222	$ 73,979	$ 149,202	$ (19,319)	$ 55,904	$ 102,669	$ 158,573
Interest Expense	40,542	1,493	353	42,388	-	42,388	(1,907)	40,481	-	40,481
State Income Tax - Current Period	1,919	-	-	1,919	-	1,919	-	1,919	-	1,919
	25,855	8,255	(3,195)	30,916	73,979	104,895	(17,412)	13,503	102,669	116,173
Reconciling Amounts:										
Total Additional Income and Unallowable Deductions	89,953	(2,405)	2,503	90,051	-	90,051	655	90,706	-	90,706
Total Additional Deductions and Nontaxable Income	161,960	(1,417)	-	160,543	-	160,543	-	160,543	-	160,543
Adjusted Taxable Income	(46,152)	7,267	(692)	(39,577)	73,979	34,403	(16,757)	(56,334)	102,669	46,335
Federal Income Tax										
FIT - 21%	(9,692)	1,526	(145)	(8,311)	15,536	7,225	(3,519)	(11,830)	21,561	9,730
NOL Carryforward Adjustment	9,692	(3,159)	116	6,649	(12,429)	(5,780)	2,815	9,464	(17,248)	(7,784)
R&D Credit/Rounding								-		
Total	-	(1,633)	(29)	(1,662)	3,107	1,445	(704)	(2,366)	4,313	1,946
Deferred Taxes	3,585	3,554	(591)	6,548	11,419	17,967	(2,715)	3,833	15,847	19,679
Total Federal Income Taxes	**$ 3,585**	**$ 1,921**	**$ (620)**	**$ 4,886**	**$ 14,526**	**$ 19,412**	**$ (3,419)**	**$ 1,467**	**$ 20,160**	**$ 21,625**

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations State Income Tax
For the Rate Year Ended June 30, 2025
($000)

	Recommended Decision							CH Exceptions			
	Recommended Decision (RD)	RD Updates	As Updated	Corrections	RD as Updated & Corrected	Impact of Rate Increase	Revenue Requirement	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
Federal Taxable Income	$ 68,316	$ 9,748	$ 78,064	$ (2,842)	$ 75,222	$ 73,979	$ 149,202	$ (19,319)	$ 55,904	$ 102,669	$ 158,573
Interest Expense	40,542	1,493	42,035	353	42,388	-	42,388	(1,907)	40,481	-	40,481
Reconciling Amounts:			-		-						
Total Additional Income and Unallowable Deductions	89,953	(2,405)	87,548	2,503	90,051	-	90,051	655	90,706	-	90,706
Total Additional Deductions and Nontaxable Income	161,960	(1,417)	160,543	-	160,543	-	160,543	-	160,543	-	160,543
Federal Taxable Income	(44,233)	7,267	(36,965)	(692)	(37,658)	73,979	36,322	(16,757)	(54,415)	102,669	48,254
Additions:											
Federal Depreciation Deduction Transition Property	(17,110)	-	(17,110)	-	(17,110)		(17,110)		(17,110)	-	(17,110)
Subtractions:											
NYS Depreciation Deduction Transition Property	-	-	-	-	-		-		-	-	-
	(17,110)	-	(17,110)	-	(17,110)	-	(17,110)	-	(17,110)	-	(17,110)
NYS Taxable Income	(61,343)	7,267	(54,075)	(692)	(54,768)	73,979	19,212	(16,757)	(71,525)	102,669	31,144
State Income Tax											
NYS Income Tax - 6.5%	(3,987)	472	(3,515)	(45)	(3,560)	4,809	1,249	(1,089)	(4,649)	6,673	2,024
Capital Base Tax	1,919		1,919		1,919		1,919		1,919		1,919
NYSIT and MTA			-								
NOL Carryforward Adjustment	3,987	(472)	3,515	45	3,560	(4,809)	(1,249)	1,089	4,649	(6,673)	(2,024)
Total Current NYSIT	1,919	-	1,919	-	1,919	-	1,919	-	1,919	-	1,919
Deferred NYSIT	1,134	694	1,828	(205)	1,623	4,809	6,432	(1,132)	491	6,673	7,164
Total State Income Taxes	**$ 3,053**	**$ 694**	**$ 3,747**	**$ (205)**	**$ 3,542**	**$ 4,809**	**$ 8,351**	**$ (1,132)**	**$ 2,410**	**$ 6,673**	**$ 9,083**

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations Additional Income and Unallowable Deductions and
Electric Operations Additional Deductions and Nontaxable Income
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision				CH Exceptions	
	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	CH Exceptions	CH As Excepted
Additional Income and Unallowable Deductions						
Depreciation - Central Hudson	$ 77,019	$ (479)	$ 2,423	$ 78,963	$ 797	$ 79,760
Transportation Depreciation	6,083	(816)	80	5,347	(142)	5,205
50 Percent Meal Disallowance	341	61	-	402	-	402
Avoided Cost Interest Capitalized	3,818	(271)	-	3,547	-	3,547
Contribution in Aid of Construction	2,499	(890)	-	1,609	-	1,609
CATCH-ALL ACCOUNT	193	(10)	-	183	-	183
Total	**$ 89,953**	**$ (2,405)**	**$ 2,503**	**$ 90,051**	**$ 655**	**$ 90,706**
Additional Deductions and Nontaxable Income:						
Depreciation - Central Hudson	$ 91,777	$ (53)	$ -	$ 91,724	$ -	$ 91,724
Cost of Removal-Tax Basis	11,800	(1,327)	-	10,473	-	10,473
Property Tax Accrued-Central Hudson	15	(37)	-	(22)	-	(22)
Repair Deduction	58,331	-	-	58,331	-	58,331
Catch-All Account	37	-	-	37	-	37
Total	**$ 161,960**	**$ (1,417)**	**$ -**	**$ 160,543**	**$ -**	**$ 160,543**

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations Federal Income Tax Deferred Items
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision						CH Exceptions			
	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	Impact of Rate Increase	Revenue Requirement	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
FIT - Current Benefits Deferred										
Depreciation-Central Hudson	$ 7,299	$ 873	$ (485)	$ 7,687		$ 7,687	$ (129)	$ 7,559		$ 7,559
Avoided Cost Interest Capitalized	(552)	57		(495)		(495)		(495)		(495)
Contribution in Aid of Construction	(229)	73		(156)		(156)		(156)		(156)
Cost of Removal-Tax Basis	(3,192)	(458)		(3,650)		(3,650)		(3,650)		(3,650)
Income Tax Rate Protected	(1,044)	(68)		(1,112)		(1,112)		(1,112)		(1,112)
NOL Carryforward	(8,855)	3,060	(107)	(5,901)	11,419	5,517	(2,587)	(8,488)	15,847	7,359
Repair Allowance	(168)	-		(168)		(168)		(168)		(168)
Repair Deduction	10,326	17		10,343		10,343		10,343		10,343
Catch-All Account	-	-		-		-		-		-
FIT - Current Benefits Deferred	**$ 3,585**	**$ 3,554**	**$ (591)**	**$ 6,548**	**$ 11,419**	**$ 17,967**	**$ (2,715)**	**$ 3,833**	**$ 15,847**	**$ 19,679**

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations State Income Tax Deferred Items
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision						CH Exceptions			
	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	Impact of Rate Increase	Revenue Requirement	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
SIT - Current Benefits Deferred										
Depreciation-Central Hudson	$ 3,088	$ 289	$ (160)	$ 3,217		$ 3,217	$ (43)	$ 3,174		$ 3,174
Avoided Cost Interest Capitalized	(186)	18	-	(168)		(168)		(168)		(168)
Contribution in Aid of Construction	(85)	62	-	(23)		(23)		(23)		(23)
Cost of Removal-Tax Basis	(1,069)	(132)	-	(1,201)		(1,201)		(1,201)		(1,201)
Income Tax Rate Change Protected	(18)	(21)	-	(39)		(39)		(39)		(39)
NOL Carryforward	(3,987)	472	(45)	(3,560)	4,809	1,249	(1,089)	(4,649)	6,673	2,024
Repair Allowance	(27)	-	-	(27)		(27)		(27)		(27)
Repair Deduction	3,418	6	-	3,424		3,424		3,424		3,424
SIT - Current Benefits Deferred	**$ 1,134**	**$ 694**	**$ (205)**	**$ 1,623**	**$ 4,809**	**$ 6,432**	**$ (1,132)**	**$ 491**	**$ 6,673**	**$ 7,164**

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations Rate Base Summary
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision					CH Exceptions		
	Recommended Decision (RD)	Adj. No.	RD Updates	Corrections	RD as Updated & Corrected	Ref.	CH Exceptions	CH As Excepted
Rate Base								
Book Cost of Utility Plant	$ 2,465,398	16.	$ -	$ 1,921	$ 2,467,319	S.	$ (3,339)	$ 2,463,980
Less: Accumulated Provision for Depreciation & Amortization	(623,310)	17.	-	(407)	(623,717)	T.	(9,861)	(633,578)
Net Plant	$ 1,842,088		$ -	$ 1,514	$ 1,843,602		$ (13,200)	$ 1,830,402
Noninterest-Bearing Construction Work in Progress	11,394	18.	-	13,268	24,662	U.	5,792	30,454
Customer Advances for Undergrounding	(1,597)		-		(1,597)			(1,597)
Deferred Charges	(46,253)		-	-	(46,253)		-	(46,253)
Accumulated Deferred Federal Taxes	(188,269)	19.	20,158	-	(168,111)		-	(168,111)
Accumulated Deferred State Taxes	(38,913)	20.	7,003	-	(31,910)		-	(31,910)
Working Capital	80,730	21.	(1,043)	113	79,800	V.	2,210	82,011
Unadjusted Rate Base	1,659,180		26,118	14,895	1,700,193		(5,198)	1,694,996
EBCAP Adjustment	88,320				88,320			88,320
Rate Base	**$ 1,747,500**		**$ 26,118**	**$ 14,895**	**$ 1,788,513**		**$ (5,198)**	**$ 1,783,316**
Equity Component of Rate Base								
Rate Base	$ 1,747,500				$ 1,788,513			$ 1,783,316
Common Equity Ratio	48%				48%			50%
Common Equity	$ 838,800		$ 12,537	$ 7,150	$ 858,486		$ 33,171	**$ 891,658**
Interest Expense Deduction								
Rate Base	$ 1,747,500				$ 1,788,513			$ 1,783,316
Weighted Cost of Long Term Debt & Customer Deposits	2.32%				2.37%			2.27%
Interest Expense Deduction for Taxes	**$ 40,542**		$ 1,493	$ 353	**$ 42,388**		$ (1,907)	**$ 40,481**

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations Deferred Items - Rate Base
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision				CH Exceptions	
Deferred Charges	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	CH Exceptions	CH Revenue Requirement
MTA Tax	$ 1,130	$ -	$ -	$ 1,130	$ -	$ 1,130
Unamortized Debt Expense	3,295	-	-	3,295	-	3,295
Deferred Revenues-Attachments Rents	(1,393)	-	-	(1,393)	-	(1,393)
Unamortized Loss on Reacquired Debt	554	-	-	554	-	554
Deferred Rate Case Expenses	1,317	-	-	1,317	-	1,317
Pension/OPEB Reserve	34,297	-	-	34,297	-	34,297
Federal Tax Rate Change - Unprotected	19,311	-	-	19,311	-	19,311
Federal & NYS Tax Rate Change - Protected	(105,376)	-	-	(105,376)	-	(105,376)
Mgmt & Operational Audit Costs	615	-	-	615	-	615
Other	(3)	-	-	(3)	-	(3)
Total Deferred Charges	**$ (46,253)**	**$ -**	**$ -**	**$ (46,253)**	**$ -**	**$ (46,253)**

Accumulated Deferred Federal Income Taxes	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated &	CH Exceptions	CH Revenue Requirement
Contributions in Aid of Construction	$ 5,691	$ (472)	$ -	$ 5,219	$ -	$ 5,219
Unbilled Revenue	3,798	-	-	3,798	-	3,798
MTA Tax	(237)	-	-	(237)	-	(237)
Deferred Avoided Cost Interest Capitalized	5,216	113	-	5,329	-	5,329
Deferred Revenues- Attachment Rents	293	-	-	293	-	293
Bonds Redeemed	(8)	-	-	(8)	-	(8)
Cost of Removal	9,213	(732)	-	8,481	-	8,481
Repair Allowance	(2,761)	-	-	(2,761)	-	(2,761)
Normalized Depreciation	(163,883)	94	-	(163,789)	-	(163,789)
MACRS - Capital Reliability Program	332	1	-	333	-	333
Prepaid Insurance	(464)	-	-	(464)	-	(464)
Mgmt & Operational Audit Costs	(129)	-	-	(129)	-	(129)
Repair Deduction	(87,206)	4,893	-	(82,313)	-	(82,313)
NOL Carryforward	28,369	16,260	-	44,629	-	44,629
Rate Case Expenses	(277)	-	-	(277)	-	(277)
Federal Tax Rate Change - Unprotected	(4,055)	-	-	(4,055)	-	(4,055)
Federal & NYS Tax Rate Change - Protected	22,129	-	-	22,129	-	22,129
Other	(4,290)	1	-	(4,289)	-	(4,289)
Total Deferred Taxes	**$ (188,269)**	**$ 20,158**	**$ -**	**$ (168,111)**	**$ -**	**$ (168,111)**

Accumulated Deferred State Income Taxes	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated &	CH Exceptions	CH Revenue Requirement
Normalized Depreciation	$ (38,798)	$ 22	$ -	$ (38,776)	$ -	$ (38,776)
MTA Tax	(73)	-	-	(73)	-	(73)
Deferred Avoided Cost Interest Capitalized	1,615	35	-	1,650	-	1,650
Deferred Revenues- Attachment Rents	91	-	-	91	-	91
Bonds Redeemed	-	-	-	-	-	-
Cost of Removal	2,869	(234)	-	2,635	-	2,635
Repair Allowance	(710)	-	-	(710)	-	(710)
Contributions in Aid of Construction	1,735	(120)	-	1,615	-	1,615
Unbilled Revenue	1,176	-	-	1,176	-	1,176
MACRS - Capital Reliability Program	114	(3)	-	111	-	111
Prepaid Insurance	(144)	-	-	(144)	-	(144)
Mgmt & Operational Audit Costs	(40)	-	-	(40)	-	(40)
Repair Deduction	(28,869)	1,620	-	(27,249)	-	(27,249)
NOL Carryforward	16,204	5,682	-	21,886	-	21,886
Rate Case Expenses	(86)	-	-	(86)	-	(86)
Federal Tax Rate Change - Unprotected	(1,255)	-	-	(1,255)	-	(1,255)
Federal & NYS Tax Rate Change - Protected	6,849	-	-	6,849	-	6,849
Other	409	1	-	410	-	410
Total Deferred Taxes	**$ (38,913)**	**$ 7,003**	**$ -**	**$ (31,910)**	**$ -**	**$ (31,910)**

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations Working Capital - Rate Base
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision				CH Exceptions	
	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	CH Exceptions	CH As Excepted
Materials and Supplies						
Other Material and Supplies	$ 23,881	$ -	$ -	$ 23,881	$ -	$ 23,881
Prepayments						
Prepaid Property Taxes	$ 14,879	-	$ -	$ 14,879	$ -	$ 14,879
Prepaid Insurance	1,711	-	-	1,711	-	1,711
Cloud Computing Prepayments	182	-	-	182	-	182
Other Prepayments	6,752	-	-	6,752	-	6,752
Prepayments Working Capital	$ 23,524	$ -	$ -	$ 23,524	$ -	$ 23,524
Operation and Maintenance						
Cash Working Capital @ 1/8	$ 33,325	$ (1,043)	$ 113	$ 32,395	$ 2,210	$ 34,606
Total Working Capital	**$ 80,730**	**$ (1,043)**	**$ 113**	**$ 79,800**	**$ 2,210**	**$ 82,011**

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations Capital Structure
For the Rate Year Ended June 30, 2025

Recommended Decision as Filed

	Ratio	Adj. No./ Ref.	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	51.8%		4.46%	2.31%	2.31%
Customer Deposits	0.3%		4.20%	0.01%	0.01%
Common Equity	48.0%		9.20%	4.42%	5.98%
	100.0%			6.74%	8.30%

Recommended Decision as Updated

	Amount	Ratio	Adj. No./ Ref.	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 1,361,900	51.7%	22.	4.55%	2.36%	2.36%
Customer Deposits	6,740	0.3%		4.20%	0.01%	0.01%
Common Equity	1,263,360	48.0%		9.20%	4.42%	5.98%
	$ 2,632,000	100.0%			6.79%	8.35%

Central Hudson Exception

	Ratio	Adj. No./ Ref.	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	49.7%		4.55%	2.26%	2.26%
Customer Deposits	0.3%		4.20%	0.01%	0.01%
Common Equity	50.0%	X.	9.80%	4.90%	6.63%
	100.0%			7.17%	8.90%

Central Hudson Gas & Electric Corporation
Case 23-E-0418
Electric Operations Basis Point Values
For the Rate Year Ended June 30, 2025

	Recommended Decision as Filed	Recommended Decision as Updated	Central Hudson Exception
Rate Base ($000)	$1,747,500	$1,788,513	$1,783,316
x Equity Ratio	48%	48%	50%
Equity component of Rate Base ($000)	$838,800	$858,486	$891,658
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$83,900	$85,800	$89,200
Pre-tax value of 1 BP - whole dollars	$113,600	$116,200	$120,800

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
ELECTRIC OPERATIONS
SUMMARY OF UPDATES & CORRECTIONS
TWELVE MONTHS ENDED JUNE 30, 2025

	Operating Income Adjustments:	RD Update	Corrections	RD Page Reference (if applicable)	Additional Notes
1.	Update Legacy Hydro Revenues to align with RD position		484	pg. 482	
2.A.	Tracking adjustment for Non-Major Storm Restoration update (refer to Adjustment No. 7)	310			
2.B.	Correction for formula error in labor calculation to align with FTEs supported in the RD		25		One FTE approved by the RD was priced out at $0.
3.A.	Correction for formula error in HY + Inflation Methodology		335	pg. 88	Employee contributions, a component of total medical expense, is the only component that was not projected by applying inflation to historic year actuals.
3.B.	Correction for calculation error of cost and employee contributions of incremental employees		112	pg. 88	Total medical cost per incremental FTE was erroneously calculated. That is, total historic year costs were divided by a number other than historic year participants to arrive at a cost per employee. As a result, cost per incremental employee was understated.
	Total Adjustment		447		
4.	Update Pension Forecast with latest known projection	(8,445)		pg. 89	
5.	Update OPEB Forecast with latest known projection	(205)		pg. 89	
6.	Update Amortization of Major Strom Reserve Regulatory Asset	1,265		Pg. 166 (fn. 408)	
7.	Update Non-Major Storm Restoration (as identified on Exhibit __ (RRP-9))	(414)			
8.	Correct Transportation Depreciation expense - reflect alignment of Company and Staff plant models		46		The net plant model used in the development of the RD revenue requirements is not aligned with the more precise methodology used in the Company model.
9.	Update to Consulting Services expense (Exhibit __ (RRP-9) Outcomes of Generic Proceedings)	87			
10.	Update Energy Efficiency program costs (as identified on Exhibit __ (RRP-9))	(939)			
11.	Correct Amortization of Depreciation Reserve to align with RD proposed depreciation rates		385		The rate allowance included in the RD does not conform with the recommendation of the RD.
12.	Update for latest known Property Taxes (as identified on Exhibit __ (RRP-9))	(1,409)			
13.	Payroll Taxes - Tracking Adjustment	2			
14.	Correct Depreciation expense - reflect alignment of Company and Staff plant models		2,423		The net plant model used in the development of the RD reflected assumptions and calculations related to capital that were not aligned with the recommendations of the RD. Additionally, there were some formulas that need to be updated to better align the Staff model with the more precise methodology of the Company model. The corrections had an impact on depreciation expense.
15.A.	Federal & State Income Tax Adjustment - Statutory Rate on Changes to Pre-Tax Operating Income	2,551	(740)		
15.B	Effect of Interest Expense and Schedule M Deductions (Tracking Adjustments)	64	(86)		
	Total Adjustment	2,615	(826)		
	Total Adjustment to Operating Income	7,133	(2,016)		

Rate Base Adjustments:		RD Update	Corrections	RD Page Reference (if applicable)	Additional Notes
16.	Correct Book Cost of Utility Plant - reflect alignment of Company and Staff plant models		1,921		The net plant model used in the development of the RD reflected assumptions and calculations related to capital that were not aligned with the recommendations of the RD. Additionally, there were some formulas that need to be updated to better align the Staff model with the more precise methodology of the Company model. The corrections had an impact on depreciation expense. (Applicable to lines 16-18)
17.	Correct Accumulated Depreciation Reserve- reflect alignment of Company and Staff plant models		(407)		
18.	Correct Non-Interest Bearing CWIP - reflect alignment of Company and Staff plant models		13,268		
19.	Reflect Company Update of Accumulated Deferred FIT	20,158	-	pg. 219	
20.	Reflect Company Update of Accumulated Deferred FIT	7,003	-	pg. 219	
21.	Reflect O&M Tracking Adjustment in Working Capital	(1,043)	113		
	Total Rate Base Adjustment	26,118	14,895		

Capitalization Adjustments		RD Update	Corrections	RD Page Reference (if applicable)	Additional Notes
22.	Cost Rate of Long-Term Debt	4.55%		pg. 267	

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
ELECTRIC OPERATIONS
SUMMARY OF CENTRAL HUDSON EXCEPTIONS
TWELVE MONTHS ENDED JUNE 30, 2025

Operating Income Adjustments:		Central Hudson Exceptions
A.	Labor - Vacancy Rate	3,256
	Labor - Capital vs Expense Distribution Rate	1,699
	Labor - Total Headcount	3,118
	Labor - Escalation Factor for all Non-Union (4.0% vs 4.5%)	256
	Labor - Latest know escalation per TDSO Contract	39
	Labor - Compounding Effects of Adjustments	299
	Total Labor Exception	8,667
B.	Employee Benefits - Headcount Tracking Adjustment	917
	Employee Benefits - Mercer Projection vs. Inflation	1,721
	Employee Benefits - Labor Distribution	303
	Employee Benefits - Compounding Effects of Adjustments	324
	Total Employee Benefit Exceptions	3,265
C.	Pension Expense - Reflect Company Labor Distribution	52
D.	OPEB Expense - Reflect Company Labor Distribution	4
E.	Employee Training - Track Company Proposed Headcount	123
F.	Regulatory Commission General Assessment - Reflect projection @ historic actual growth rate	324
G.	Major Strom Reserve - Based on an average of a full 10 year history (no exclusions)	4,064
H.	Transportation Depreciation - Company levels of Capital @ RD depreciation rates	(82)
I.	Consulting & Professional Services - Include costs for emergent work	160
	Consulting & Professional Services - Reduction to DSIP costs (DPS-686)	(40)
	Total Consulting & Professional Services Exception	120
J.	Miscellaneous General Expense - Include incremental recruiting expense	80
K.	Injuries & Damages - Headcount & Labor Distribution Tracking Adjustment	36
L.	Miscellaneous Charges - Continue to include NTC program	66
M.	Productivity Imputation - Tracking Adjustment (incl. Pension & OPEB)	93
N.	Amortization of Depreciation Reserve - Aligned with RD Depreciation Rates @ 10 year amortization	870
O.	Payroll Taxes - Tracking Adjustment	599
P.	Sales Tax - correct for erroneous adjustment made by Staff based on misunderstanding of projection workpaper	241
Q.	Depreciation Expense - Company levels of Capital @ RD depreciation rates	797
R.	Federal & State Income Tax Adjustment - Statutory Rate on Changes to Pre-Tax Operating Income	(5,049)
	Effect of Interest Expense and Schedule M Deductions (Tracking Adjustments)	498
	Total Income Tax Effect	(4,551)
	Total Adjustment to Operating Income	14,768

Rate Base Adjustments:		Central Hudson Exceptions
S.	Book Cost of Utility Plant - Company CapEx position w/updates of actuals through January 2024	(3,339)
T.	Accumulated Depreciation Reserve - reflect adoption of RD Depreciation Factors w/updates of actuals through January 2024	(9,861)
U.	Non-Interest Bearing CWIP - Company CapEx position w/updates of actuals through January 2024	5,792
V.	Reflect O&M Tracking Adjustment in Working Capital	2,210
	Total Rate Base Adjustment	(5,198)

Capitalization Adjustments:		Central Hudson Exceptions
W.	Common Equity Ratio	50%
	Return on Equity Cost Rate	9.8%

Central Hudson Gas & Electric Corporation
Net Electric Deferred Balances Available For Moderation

Description	Projected Balance @ July 1, 2025 Gross	FIT	FIT Contra	SIT	Net
Rate Moderator - Electric	(16,406,786)	3,445,400	(223,900)	1,066,400	(12,118,886)
Pension Plan - Electric	(15,177,772)	3,187,300	(207,200)	986,600	(11,211,072)
Property Taxes - Electric	(11,159,830)	2,343,600	(152,300)	725,400	(8,243,130)
Utility Asset Sale to Transco	(4,338,300)	911,000	(59,200)	282,000	(3,204,500)
Net Plant Target Shortfall - Case 20-E-0428 Electric	(4,514,000)	947,900	(61,600)	293,400	(3,334,300)
Negative Revenue Adjustments - Electric	(5,763,200)	1,210,300	(78,700)	374,600	(4,257,000)
REV Demonstration Projects	(111,335)	23,400	(1,500)	7,200	(82,235)
OPEB - Electric	(3,106,540)	652,400	(42,400)	201,900	(2,294,640)
Economic Development	(1,195,776)	251,100	(16,300)	77,700	(883,276)
Carrying Charges - Rate Moderator - Electric	(633,304)	133,000	(8,700)	41,200	(467,804)
Carrying Charges - Property Taxes - Electric	(456,163)	95,800	(6,200)	29,700	(336,863)
Carrying Charges - Environmental SIR Costs & Recovery Deferral - Electric	(361,913)	76,000	(4,900)	23,500	(267,313)
Tax Rate Change - Other Plant - Electric	(576,400)	121,000	(7,900)	37,500	(425,800)
Sales Tax Refund/Assessment	(125,000)	26,300	(1,700)	8,100	(92,300)
Carrying Charges - Utility Asset Sale to Transco	(125,936)	26,400	(1,700)	8,200	(93,036)
Energy Affordability Program Deferral - Electric	0	0	0	0	0
Carrying Charges - Economic Development	(28,609)	6,000	(400)	1,900	(21,109)
Carrying Charges - OPEB - Electric	(2,098)	400	0	100	(1,598)
Carrying Charges - Pension Plan - Electric	(12,159)	2,600	(200)	800	(8,959)
Carrying Charges - Sales Tax Refund/Assessment	(16,050)	3,400	(200)	1,000	(11,850)
Carrying Charges - CDG Consolidated Billing	(3,613)	800	0	200	(2,613)
Carrying Charges - Energy Affordability Program Deferral - Electric	(75,991)	16,000	(1,000)	4,900	(56,091)
Total Credits - Electric	**(64,190,775)**	**13,480,100**	**(876,000)**	**4,172,300**	**(47,414,375)**
Uncollectible Write-Offs	9,369,749	(1,967,600)	127,900	(609,000)	6,921,049
Deferral of Interest - Electric	4,829,000	(1,014,100)	65,900	(313,900)	3,566,900
Asbestos Litigation Costs	36,626	(7,700)	500	(2,400)	27,026
COVID Lost Revenue Deferral - Electric	2,088,833	(438,700)	28,500	(135,800)	1,542,833
DEI Order 22-M-0314 Elec	0	0	0	0	0
Research & Development - Electric	2,395,736	(503,100)	32,700	(155,700)	1,769,636
Carrying Charges - Major Storm Reserve - Electric	1,823,430	(382,900)	24,900	(118,500)	1,346,930
Carrying Charges - Energy Efficiency & Heat Pump Programs	1,091,182	(229,100)	14,900	(70,900)	806,082
Variable Rate Interest - Electric	1,080,876	(227,000)	14,800	(70,300)	798,376
Payment by Credit Card - Electric	310,155	(65,100)	4,200	(20,200)	229,055
Geothermal Dist Loop Study*	200,000	(42,000)	2,700	(13,000)	147,700
Stray Voltage - Electric	413,518	(86,800)	5,600	(26,900)	305,418
Carrying Charges - Uncollectible Write-Offs	164,344	(34,500)	2,200	(10,700)	121,344
CDG Consolidated Billing	282,543	(59,300)	3,900	(18,400)	208,743
Carrying Charges - Targeted Demand Management Program - Electric	172,488	(36,200)	2,400	(11,200)	127,488
Carrying Charges - COVID Lost Revenues - Electric	220,014	(46,200)	3,000	(14,300)	162,514
Carrying Charges - Deferral of Interest - Electric	105,869	(22,200)	1,400	(6,900)	78,169
Carrying Charges - Asbestos Litigation Costs	1,300	(300)	0	(100)	900
Carrying Charges - Electric RAM	58,719	(12,300)	800	(3,800)	43,419
Carrying Charges - Variable Rate Interest Undercollection - Electric	28,896	(6,100)	400	(1,900)	21,296
Electric Vehicles Time of Use Deferral - Electric	25,643	(5,400)	400	(1,700)	18,943
Carrying Charges - Management Audit Costs - Electric	15,422	(3,200)	200	(1,000)	11,422
Carrying Charges - DEI Order 22-M-0314 - Electric	284	(100)	0	0	184
Carrying Charges - Payment by Credit Card - Electric	7,556	(1,600)	100	(500)	5,556
Carrying Charges - REV Demonstration Projects	2,535	(500)	0	(200)	1,835
Carrying Charges - Stray Voltage - Electric	10,027	(2,100)	100	(700)	7,327
Carrying Charges - Call Volume Overflow - Electric	2,910	(600)	0	(200)	2,110
Carrying Charges - Electric Vehicles Time of Use Deferral - Electric	655	(100)	0	0	555
Total Debits - Electric	**24,738,310**	**(5,194,800)**	**337,500**	**(1,608,200)**	**18,272,810**
Net Credit Available for Moderation after Offset - Electric	**(39,452,465)**	**8,285,300**	**(538,500)**	**2,564,100**	**(29,141,565)**

* The RD at pages 252-253 discusses approval in the 2021 Rate Plan for deferral of costs related to conducting a Geothermal Distric Energy Loop feasibility study, up to $200,000.
The discussion agrees with the recovery of $170,000, which reflects the balance at that time. Final update of costs incurred and reflected here is $200,000.

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations Income Statement and Rate of Return Calculation
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision							CH Exceptions				
	Recommended Decision (RD)	Adj. No.	RD Updates	Corrections	RD as Updated & Corrected	Rate Increase	Revenue Requirement	Ref.	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
Operating Revenues												
Own Territory Delivery Revenues	$ 135,884		$ -	$ -	$ 135,884	$ 26,476	$ 162,360			$ 135,884	$ 36,976	$ 172,860
Revenue Taxes	3,152		-	-	3,152	1,049	4,201			$ 3,152	1,465	4,617
Subtotal - Delivery Rates	139,036		-	-	139,036	27,525	166,561		-	139,036	38,441	177,477
Interruptible & Sales to Generators	3,200		-	-	3,200		3,200			$ 3,200		3,200
Danskammer Revenue	1,000		-	-	1,000		1,000			$ 1,000		1,000
Other Operating Revenues	1,435		-	-	1,435	176	1,611			$ 1,435	246	1,681
Total Operating Revenues	**144,671**		**-**	**-**	**144,671**	**27,701**	**172,372**		**-**	**144,671**	**38,687**	**183,358**
Operating Expenses												
Labor	25,824	1.		7	25,831		25,831	A.	2,364	28,195		28,195
Executive Incentive Compensation	230				230		230			230		230
Management Variable Pay	850				850		850			850		850
Employee Benefits	4,606	2.		127	4,733		4,733	B.	906	5,639		5,639
Pension	(2,086)	3.	(2,395)		(4,481)		(4,481)	C.	30	(4,451)		(4,451)
Other Post-Employment Benefits	(1,649)	4.	(59)		(1,708)		(1,708)	D.	8	(1,700)		(1,700)
Employee Training, Safety & Reliability	952				952		952	E.	45	997		997
System Engineering & Compliance	106				106		106			106		106
T&D Repairs & Maintenance	3,384	5.		(75)	3,309		3,309	F.	75	3,384		3,384
Pipeline Integrity & Inspection	2,912				2,912		2,912			2,912		2,912
Gas Leaks Repairs - Distribution Main	760				760		760			760		760
Meter Installations, Removals & Maintenance	(381)				(381)		(381)			(381)		(381)
Research & Development	800				800		800			800		800
Economic Development	-				-		-			-		-
Informational & Institutional Advertising	120				120		120			120		120
Meter Reading, Collections & Call Volume Overflow	1,445				1,445		1,445			1,445		1,445
Bill Print	194				194		194			194		194
Postage	419				419		419			419		419
Payment by Credit/Debit Card	319				319		319			319		319
Low Income Program	3,503				3,503		3,503			3,503		3,503
Uncollectible Accounts	1,323				1,323		1,323			1,323		1,323
Regulatory Commission General Assessment	757				757		757	G.	91	848		848
Environmental SIR Costs	197				197		197			197		197
Environmental - All Other	52				52		52			52		52
Information Technology	3,927				3,927		3,927			3,927		3,927
Telephone	495				495		495			495	-	495
Rental Agreements	537				537		537			537		537
Security of Infrastructure	926				926		926			926		926
Maintenance of Building and Supplies	648				648		648			648		648
Materials & Supplies	382				382		382	H.	176	558		558
Stores Clearing to Expense	49				49		49	I.	63	112		112
Transportation Depreciation	993	6.		15	1,008		1,008	J.	(27)	981		981
Transportation Fuel	449				449		449			449		449
Transportation All Others	719				719		719			719		719
Rate Case Expenses	140				140		140			140		140
Legal Services	466				466		466			466		466
Consulting & Professional Services	1,213				1,213		1,213	K.	40	1,253		1,253
Miscellaneous General Expense	1,348				1,348		1,348	L.	20	1,368		1,368
Injuries & Damages	1,427				1,427		1,427	M.	10	1,437		1,437
Other Operating Insurance	312				312		312			312		312
Office Supplies	307				307		307			307		307
Management & Operational Audit Costs	32				32		32			32		32
Management & Operational Audit Savings	-				-		-			-		-
Energy Efficiency	1,939				1,939		1,939			1,939		1,939
Miscellaneous Charges	828				828		828	N.	16	844		844
Amortization of Unprotected Asset (TCJA)	376				376		376			376		376
Productivity Imputation	(333)				(333)		(333)	O.	28	(305)		(305)
Recovery/Refund of Rate Change Timing	-				-		-			-		-
Inflation Reduction	(34)				(34)		(34)			(34)		(34)
Gas Safety Programs	-				-		-			-		-
Amortization of Depreciation Reserve Adjustment	57				57		57	P.	1,749	1,806		1,806
Total Operating Expenses	**61,841**		**(2,454)**	**74**	**59,461**	**-**	**59,461**		**5,593**	**65,054**	**-**	**65,054**
Other Deductions												
Property Taxes	19,382	7.	(276)		19,106		19,106			19,106		19,106
Revenue Taxes	3,152				3,152	1,049	4,201			3,152	1,465	4,617
Payroll Taxes	1,763				1,763		1,763	Q.	163	1,926		1,926
Other Taxes	324				324		324	R.	60	384		384
Depreciation	27,948	8.		598	28,546		28,546	S.	228	28,774		28,774
Total Other Deductions	**52,569**		**(276)**	**598**	**52,891**	**1,049**	**53,940**		**451**	**53,342**	**1,465**	**54,807**
Income Taxes												
Federal Income Taxes	1,881	9.	410	(169)	2,122	5,233	7,356	T.	(1,076)	1,047	7,309	8,356
State Income Taxes	1,066	9.	191	(56)	1,201	1,732	2,933	T.	(355)	845	2,419	3,264
Total Income Taxes	**2,947**		**601**	**(225)**	**3,323**	**6,965**	**10,288**		**(1,431)**	**1,892**	**9,728**	**11,620**
Total Operating Revenue Deductions	**117,357**		**(2,129)**	**447**	**115,675**	**8,014**	**123,689**		**4,613**	**120,288**	**11,193**	**131,481**
Net Operating Income	**$ 27,314**		**$ 2,129**	**$ (447)**	**$ 28,996**	**$ 19,687**	**$ 48,683**		**$ (4,613)**	**$ 24,383**	**$ 27,494**	**$ 51,877**
Rate Base	**$ 731,381**		**$ (22,572)**	**$ 8,163**	**$ 716,972**	**$ -**	**$ 716,972**		**$ 6,557**	**$ 723,529**	**$ -**	**$ 723,529**
Rate of Return	**3.73%**						**6.79%**					**7.17%**

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations Federal Income Tax
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision						CH Exceptions			
	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	Rate Increase	Revenue Requirement	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
Operating Income Before FIT, SIT, Interest	$ 30,261	$ 2,730	$ (672)	$ 32,319	$ 26,653	$ 58,971	$ (6,044)	$ 26,275	$ 37,222	$ 63,497
Interest Expense	16,968	(169)	193	16,992	-	16,992	(568)	16,424	-	16,424
State Income Tax - Current Period	480	-	-	480	-	480	-	480	-	480
	12,813	2,899	(865)	14,846	26,653	41,499	(5,476)	9,371	37,222	46,593
Reconciling Amounts:										
Total Additional Income and Unallowable Deductions	31,335	(553)	618	31,400	-	31,400	192	31,592	-	31,592
Total Additional Deductions and Nontaxable Income	66,663	(211)	-	66,452	-	66,452	-	66,452	-	66,452
Adjusted Taxable Income	(22,515)	2,557	(248)	(20,206)	26,653	6,447	(5,284)	(25,489)	37,222	11,733
Federal Income Tax										
FIT - 21%	(4,728)	537	(52)	(4,243)	5,597	1,354	(1,110)	(5,353)	7,817	2,464
NOL Carryforward Adjustment	4,728	(1,375)	42	3,394	(4,478)	(1,083)	888	4,282	(6,254)	(1,971)
R&D Credit/Rounding								-		
Total	-	(838)	(10)	(849)	1,119	271	(222)	(1,071)	1,563	493
Deferred Taxes	1,881	1,248	(159)	2,971	4,114	7,085	(854)	2,117	5,746	7,863
Total Federal Income Taxes	**$ 1,881**	**$ 410**	**$ (169)**	**$ 2,122**	**$ 5,233**	**$ 7,356**	**$ (1,076)**	**$ 1,047**	**$ 7,309**	**$ 8,356**

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations State Income Tax
For the Rate Year Ended June 30, 2025
($000)

	Recommended Decision						CH Exceptions			
	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	Rate Increase	Revenue Requirement	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
Federal Taxable Income	$ 30,261	$ 2,730	$ (672)	$ 32,319	$ 26,653	$ 58,971	$ (6,044)	$ 26,275	$ 37,222	$ 63,497
Interest Expense	16,968	(169)	193	16,992	-	16,992	(568)	16,424	-	16,424
Reconciling Amounts:				-						
Total Additional Income and Unallowable Deductions	31,335	(553)	618	31,400	-	31,400	192	31,592	-	31,592
Total Additional Deductions and Nontaxable Income	66,663	(211)	-	66,452	-	66,452	-	66,452	-	66,452
Federal Taxable Income	(22,035)	2,557	(248)	(19,726)	26,653	6,927	(5,284)	(25,009)	37,222	12,213
Additions:										
Federal Depreciation Deduction Transition Property	(5,735)	-		(5,735)		(5,735)		(5,735)	-	(5,735)
Subtractions:										
NYS Depreciation Deduction Transition Property	-	-		-		-		-	-	-
	(5,735)	-	-	(5,735)	-	(5,735)	-	(5,735)	-	(5,735)
NYS Taxable Income	(27,770)	2,557	(248)	(25,461)	26,653	1,192	(5,284)	(30,744)	37,222	6,478
State Income Tax										
NYS Income Tax - 6.5%	(1,805)	166	(16)	(1,655)	1,732	77	(343)	(1,998)	2,419	421
Capital Base Tax	480			480		480		480		480
NYSIT and MTA										
NOL Carryforward Adjustment	1,805	(166)	16	1,655	(1,732)	(77)	343	1,998	(2,419)	(421)
Total Current NYSIT	480	-	-	480	-	480	-	480	-	480
Deferred NYSIT	586	191	(56)	721	1,732	2,453	(355)	365	2,419	2,784
Total State Income Taxes	**$ 1,066**	**$ 191**	**$ (56)**	**$ 1,201**	**$ 1,732**	**$ 2,933**	**$ (355)**	**$ 845**	**$ 2,419**	**$ 3,264**

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations Additional Income and Unallowable Deductions and
Gas Operations Additional Deductions and Nontaxable Income
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision				CH Exceptions	
	Recommended Decision (RD)	**RD Updates**	**Corrections**	**RD as Updated & Corrected**	**CH Exceptions**	**CH As Excepted**
Additional Income and Unallowable Deductions						
Depreciation - Central Hudson	$ 28,005	$ (57)	$ 598	$ 28,546	$ 228	$ 28,774
Transportation Depreciation	1,521	(204)	20	1,337	(36)	1,301
50 Percent Meal Disallowance	85	16	-	101	-	101
Avoided Cost Interest Capitalized	975	(20)	-	955	-	955
Contribution in Aid of Construction	700	(284)	-	416	-	416
CATCH-ALL ACCOUNT	49	(4)	-	45	-	45
Total	**$ 31,335**	**$ (553)**	**$ 618**	**$ 31,400**	**$ 192**	**$ 31,592**
Additional Deductions and Nontaxable Income:						
Depreciation - Central Hudson	$ 32,533	$ 243	$ -	$ 32,776	$ -	$ 32,776
Cost of Removal-Tax Basis	2,077	(437)	-	1,640	-	1,640
Property Tax Accrued-Central Hudson	7	(17)	-	(10)	-	(10)
Repair Deduction	32,037	-	-	32,037	-	32,037
Catch-All Account	9	-	-	9	-	9
Total	**$ 66,663**	**$ (211)**	**$ -**	**$ 66,452**	**$ -**	**$ 66,452**

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations Federal Income Tax Deferred Items
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision						CH Exceptions			
	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	Impact of Rate Increase	Revenue Requirement	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
FIT - Current Benefits Deferred										
Depreciation-Central Hudson	$ 2,554	$ 195	$ (120)	$ 2,629		$ 2,629	$ (38)	$ 2,591		$ 2,591
Avoided Cost Interest Capitalized	(158)	2		(156)		(156)	-	(156)		(156)
Contribution in Aid of Construction	(14)	(109)		(123)		(123)	-	(123)		(123)
Cost of Removal-Tax Basis	(1,562)	(174)		(1,736)		(1,736)	-	(1,736)		(1,736)
Income Tax Rate Protected	(394)	(22)		(416)		(416)	-	(416)		(416)
NOL Carryforward	(4,349)	1,340	(38)	(3,047)	4,114	1,067	(816)	(3,863)	5,746	1,883
Repair Deduction	5,804	16		5,820		5,820	-	5,820		5,820
Catch-All Account	-	-		-		-	-	-		-
FIT - Current Benefits Deferred	**$ 1,881**	**$ 1,248**	**$ (159)**	**$ 2,971**	**$ 4,114**	**$ 7,085**	**$ (854)**	**$ 2,117**	**$ 5,746**	**$ 7,863**

Central Hudson Gas & Electric Corporation
23-G-0419
Gas Operations State Income Tax Deferred Items
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision						CH Exceptions			
	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	Impact of Rate Increase	Revenue Requirement	CH Exceptions	CH As Excepted	Impact of Rate Increase	CH Revenue Requirement
SIT - Current Benefits Deferred										
Depreciation-Central Hudson	$ 988	$ 65	$ (40)	$ 1,013		$ 1,013	$ (12)	$ 1,000		$ 1,000
Avoided Cost Interest Capitalized	(53)	10	-	(43)		(43)	-	(43)		(43)
Contribution in Aid of Construction	(1)	(36)	-	(37)		(37)	-	(37)		(37)
Cost of Removal-Tax Basis	(454)	(19)	-	(473)		(473)	-	(473)		(473)
Income Tax Rate Change Protected	(10)	(1)	-	(11)		(11)	-	(11)		(11)
NOL Carryforward	(1,805)	166	(16)	(1,655)	1,732	77	(343)	(1,998)	2,419	421
Repair Deduction	1,921	6	-	1,927		1,927	-	1,927		1,927
SIT - Current Benefits Deferred	**$ 586**	**$ 191**	**$ (56)**	**$ 721**	**$ 1,732**	**$ 2,453**	**$ (355)**	**$ 365**	**$ 2,419**	**$ 2,784**

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations Rate Base Summary
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision					CH Exceptions		
	Recommended Decision (RD)	Adj. No.	RD Updates	Corrections	RD as Updated &	Ref.	CH Exceptions	CH As Excepted
Rate Base								
Book Cost of Utility Plant	$ 1,017,724	10.	$ -	$ 6,655	$ 1,024,379	U.	$ 933	$ 1,025,312
Less: Accumulated Provision for								
Depreciation & Amortization	(224,318)	11.	-	224	(224,094)	V.	1,431	(222,663)
Net Plant	$ 793,406		$ -	$ 6,879	$ 800,285		$ 2,364	$ 802,649
Noninterest-Bearing Construction Work in Progress	4,751	12.	-	1,275	6,026	W.	3,494	9,520
Customer Advances for Undergrounding	(850)		-		(850)			(850)
Deferred Charges	(32,056)		-	-	(32,056)		-	(32,056)
Accumulated Deferred Federal Taxes	(78,173)	13.	(16,313)	-	(94,486)		-	(94,486)
Accumulated Deferred State Taxes	(16,857)	14.	(5,952)	-	(22,809)		-	(22,809)
Working Capital	24,020	15.	(307)	9	23,722	X.	699	24,421
Unadjusted Rate Base	694,241		(22,572)	8,163	679,832		6,557	686,389
EBCAP Adjustment	37,140		-	-	37,140			37,140
Rate Base	**$ 731,381**		**$ (22,572)**	**$ 8,163**	**$ 716,972**		**$ 6,557**	**$ 723,529**
Equity Component of Rate Base								
Rate Base	$ 731,381				$ 716,972			$ 723,529
Common Equity Ratio	48%				48%			50%
Common Equity	$ 351,063		$ (10,834)	$ 3,918	$ 344,147		$ 17,618	**$ 361,765**
Interest Expense Deduction								
Rate Base	$ 731,381				$ 716,972			$ 723,529
Weighted Cost of Long Term Debt & Customer Deposits	2.32%				2.37%			2.27%
Interest Expense Deduction for Taxes	**$ 16,968**		$ (169)	$ 193	**$ 16,992**		$ (568)	**$ 16,424**

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations Deferred Items - Rate Base
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision				CH Exceptions	
Deferred Charges	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	CH Exceptions	CH Revenue Requirement
MTA Tax	$ 480	$ -	$ -	$ 480	$ -	$ 480
Unamortized Debt Expense	1,414	-	-	1,414	-	1,414
Unamortized Loss on Reacquired Debt	238	-	-	238	-	238
Mgmt & Operational Audit Costs	154	-	-	154	-	154
Federal Tax Rate Change - Unprotected	3,631	-	-	3,631	-	3,631
Federal & NYS Tax Rate Change - Protected	(38,092)	-	-	(38,092)	-	(38,092)
Rate Case Expenses	329	-	-	329	-	329
Pension/OPEB Reserve	(210)	-	-	(210)	-	(210)
Total Deferred Charges	**$ (32,056)**	**$ -**	**$ -**	**$ (32,056)**	**$ -**	**$ (32,056)**

Accumulated Deferred Federal Income Taxes	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	CH Exceptions	CH Revenue Requirement
Contributions in Aid of Construction	$ 3,003	$ (293)	$ -	$ 2,710	$ -	$ 2,710
Unbilled Revenue	1,508	-	-	1,508	-	1,508
MTA Tax	(101)	-	-	(101)	-	(101)
Deferred Avoided Cost Interest Capitalized	912	(28)	-	884	-	884
Bonds Redeemed	(3)	-	-	(3)	-	(3)
Cost of Removal	4,435	(239)	-	4,196	-	4,196
Normalized Depreciation	(67,733)	(505)	-	(68,238)	-	(68,238)
Prepaid Insurance	(116)	-	-	(116)	-	(116)
Management & Operational Audit Costs	(32)	-	-	(32)	-	(32)
Repair Deduction	(36,791)	(21,889)	-	(58,680)	-	(58,680)
NOL Carryforward	11,588	6,641	-	18,229	-	18,229
Interest Expense on Tax Reserve	-	-	-	-	-	-
Federal Tax Rate Change - Unprotected	(762)	-	-	(762)	-	(762)
Federal & NYS Tax Rate Change - Protected	7,999	-	-	7,999	-	7,999
Rate Case Expenses	(69)	-	-	(69)	-	(69)
Other	(2,011)	-	-	(2,011)	-	(2,011)
Total Deferred Taxes	**$ (78,173)**	**$ (16,313)**	**$ -**	**$ (94,486)**	**$ -**	**$ (94,486)**

Accumulated Deferred State Income Taxes	Recommended Decision (RD)	RD Updates	Corrections	RD as Updated & Corrected	CH Exceptions	CH Revenue Requirement
Normalized Depreciation	$ (16,574)	$ (124)	$ -	$ (16,698)	$ -	$ (16,698)
MTA Tax	(31)	-	-	(31)	-	(31)
Deferred Avoided Cost Interest Capitalized	277	(24)	-	253	-	253
Bonds Redeemed	-	-	-	-	-	-
Cost of Removal	1,376	(77)	-	1,299	-	1,299
Contributions in Aid of Construction	921	(67)	-	854	-	854
Unbilled Revenue	467	-	-	467	-	467
Prepaid Insurance	(36)	-	-	(36)	-	(36)
Management & Operational Audit Costs	(10)	-	-	(10)	-	(10)
Repair Deduction	(12,199)	(7,980)	-	(20,179)	-	(20,179)
NOL Carryforward	6,619	2,320	-	8,939	-	8,939
Interest Expense on Tax Reserve	-	-	-	-	-	-
Federal Tax Rate Change - Unprotected	(236)	-	-	(236)	-	(236)
Federal & NYS Tax Rate Change - Protected	2,476	-	-	2,476	-	2,476
Rate Case Expenses	(21)	-	-	(21)	-	(21)
Other	114	-	-	114	-	114
Total Deferred Taxes	**$ (16,857)**	**$ (5,952)**	**$ -**	**$ (22,809)**	**$ -**	**$ (22,809)**

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations Working Capital - Rate Base
For the Rate Year Ended June 30, 2025
($000's)

	Recommended Decision				CH Exceptions	
	Recommended Decision (RD)	**RD Updates**	**Corrections**	**RD as Updated &**	**CH Exceptions**	**CH As Excepted**
Materials and Supplies						
Other Material and Supplies	$ 8,216	$ -	$ -	$ 8,216	$ -	$ 8,216
Prepayments						
Prepaid Property Taxes	$ 6,077	-	$ -	$ 6,077	$ -	$ 6,077
Prepaid Insurance	428	-	-	428	-	428
Cloud Computing Prepayments	46	-	-	46	-	46
Other Prepayments	1,688	-	-	1,688	-	1,688
Prepayments Working Capital	$ 8,239	$ -	$ -	$ 8,239	$ -	$ 8,239
Operation and Maintenance						
Cash Working Capital @ 1/8	$ 7,565	$ (307)	$ 9	$ 7,267	$ 699	$ 7,966
Total Working Capital	**$ 24,020**	**$ (307)**	**$ 9**	**$ 23,722**	**$ 699**	**$ 24,421**

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations Capital Structure
For the Rate Year Ended June 30, 2025
($000's)

Recommended Decision as Filed

	Ratio	Adj. No./ Ref.	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	51.8%		4.46%	2.31%	2.31%
Customer Deposits	0.3%		4.20%	0.01%	0.01%
Common Equity	48.0%		9.20%	4.42%	5.98%
	100.0%			6.74%	8.30%

Recommended Decision as Updated

	Amount	Ratio	Adj. No./ Ref.	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 1,361,900	51.7%	16.	4.55%	2.36%	2.36%
Customer Deposits	6,740	0.3%		4.20%	0.01%	0.01%
Common Equity	1,263,360	48.0%		9.20%	4.42%	5.98%
	$ 2,632,000	100.0%			6.79%	8.35%

Central Hudson Exception

	Ratio	Adj. No./ Ref.	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	49.7%		4.55%	2.26%	2.26%
Customer Deposits	0.3%		4.20%	0.01%	0.01%
Common Equity	50.0%	Y.	9.80%	4.90%	6.63%
	100.0%			7.17%	8.90%

Central Hudson Gas & Electric Corporation
Case 23-G-0419
Gas Operations Basis Point Values
For the Rate Year Ended June 30, 2025

	Recommended Decision as Filed	Recommended Decision as Updated	Central Hudson Exception
Rate Base ($000)	$731,381	$716,972	$723,529
x Equity Ratio	48%	48%	50%
Equity component of Rate Base ($000)	$351,063	$344,147	$361,765
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$35,100	$34,400	$36,200
Pre-tax value of 1 BP - whole dollars	$47,500	$46,600	$49,000

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
GASOPERATIONS
SUMMARY OF UPDATES & CORRECTIONS
TWELVE MONTHS ENDED JUNE 30, 2025

	Operating Income Adjustments:	RD Update	Corrections	RD Page Reference (if applicable)	Additional Notes
1.	Correction for formula error in labor calculation to align with FTEs supported in the RD		7		One FTE approved by the RD was priced out at $0.
2.A.	Correction for formula error in HY + Inflation Methodology		95	pg. 88	Employee contributions, a component of total medical expense, is the only component that was not projected by applying inflation to historic year actuals.
2.B.	Correction for calculation error of cost and employee contributions of incremental employees		32	pg. 88	Total medical cost per incremental FTE was erroneously calculated. That is, total historic year costs were divided by a number other than historic year participants to arrive at a cost per employee. As a result, cost per incremental employee was understated.
	Total Adjustment		127		
3.	Update Pension Forecast with latest known projection	(2,395)		pg. 89	
4.	Update OPEB Forecast with latest known projection	(59)		pg. 89	
5.	Removal of Damage Prevention Patroller per RD		(75)	pg. 43	
6.	Correct Transportation Depreciation expense - reflect alignment of Company and Staff plant models		15		The net plant model used in the development of the RD revenue requirements is not aligned with the more precise methodology used in the Company model.
7.	Update for latest known Property Taxes (as identified on Exhibit __ (RRP-9))	(276)			
8.	Correct Depreciation expense - reflect alignment of Company and Staff plant models		598		The net plant model used in the development of the RD reflected assumptions and calculations related to capital that were not aligned with the recommendations of the RD. Additionally, there were some formulas that need to be updated to better align the Staff model with the more precise methodology of the Company model. The corrections had an impact on depreciation expense.
9.A.	Federal & State Income Tax Adjustment - Statutory Rate on Changes to Pre-Tax Operating Income	713	(176)		
9.B	Effect of Interest Expense and Schedule M Deductions (Tracking Adjustments)	(112)	(49)		
	Total Adjustment	601	(225)		
	Total Adjustment to Operating Income	(2,129)	447		

	Rate Base Adjustments:	RD Update	Corrections	RD Page Reference (if applicable)	Additional Notes
10.	Correct Book Cost of Utility Plant - reflect alignment of Company and Staff plant models		6,655		The net plant model used in the development of the RD reflected assumptions and calculations related to capital that were not aligned with the recommendations of the RD. Additionally, there were some formulas that need to be updated to better align the Staff model with the more precise methodology of the Company model. The corrections had an impact on depreciation expense. (Applicable to lines 10-12)
11.	Correct Accumulated Depreciation Reserve- reflect alignment of Company and Staff plant models		224		
12.	Correct Non-Interest Bearing CWIP - reflect alignment of Company and Staff plant models		1,275		
13.	Reflect Company Update of Accumulated Deferred FIT	(16,313)	-	pg. 219	
14.	Reflect Company Update of Accumulated Deferred FIT	(5,952)	-	pg. 219	
15.	Reflect O&M Tracking Adjustment in Working Capital	(307)	9		
	Total Rate Base Adjustment	(22,572)	8,163		

	Capitalization Adjustments	RD Update	Corrections	RD Page Reference (if applicable)	Additional Notes
16.	Cost Rate of Long-Term Debt	4.55%		pg. 267	

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
GAS OPERATIONS
SUMMARY OF CENTRAL HUDSON EXCEPTIONS
TWELVE MONTHS ENDED JUNE 30, 2025

Operating Income Adjustments:		**Central Hudson Exceptions**
A.	Labor - Vacancy Rate	923
	Labor - Capital vs Expense Distribution Rate	395
	Labor - Total Headcount	884
	Labor - Escalation Factor for all Non-Union (4.0% vs 4.5%)	72
	Labor - Latest know escalation per TDSO Contract	11
	Labor - Compounding Effects of Adjustments	79
	Total Labor Exception	2,364
B.	Employee Benefits - Headcount Tracking Adjustment	260
	Employee Benefits - Mercer Projection vs. Inflation	488
	Employee Benefits - Labor Distribution	70
	Employee Benefits - Compounding Effects of Adjustments	88
	Total Employee Benefit Exceptions	906
C.	Pension Expense - Reflect Company Labor Distribution	30
D.	OPEB Expense - Reflect Company Labor Distribution	8
E.	Employee Training - Track Company Proposed Headcount	45
F.	Gas T&D - Include costs for incremental damage patroller	75
G.	Regulatory Commission General Assessment - Reflect projection @ historic actual growth rate	91
H.	Materials & Supplies - Include normalization to reflect three year average	176
I.	Stores Expense - Materials & Supplies tracking adjustment	63
J.	Transportation Depreciation - Company levels of Capital @ RD depreciation rates	(27)
K.	Consulting & Professional Services - Include costs for emergent work	40
L.	Miscellaneous General Expense - Include incremental recruiting expense	20
M.	Injuries & Damages - Headcount & Labor Distribution Tracking Adjustment	10
N.	Miscellaneous Charges - Continue to include NTC program	16
O.	Productivity Imputation - Tracking Adjustment (incl. Pension & OPEB)	28
P.	Amortization of Depreciation Reserve - Aligned with RD Depreciation Rates @ 10 year amortization with full elimination for the under reserve	1,749
Q.	Payroll Taxes - Tracking Adjustment	163
R.	Sales Tax - correct for erroneous adjustment made by Staff based on misunderstanding of projection workpaper	60
S.	Depreciation Expense - Company levels of Capital @ RD depreciation rates	228
T.	Federal & State Income Tax Adjustment - Statutory Rate on Changes to Pre-Tax Operating Income	(1,580)
	Effect of Interest Expense and Schedule M Deductions (Tracking Adjustments)	148
	Total Income Tax Effect	(1,432)
	Total Adjustment to Operating Income	4,613

Rate Base Adjustments:		**Central Hudson Exceptions**
U.	Book Cost of Utility Plant - Company CapEx position w/updates of actuals through January 2024	933
V.	Accumulated Depreciation Reserve - reflect adoption of RD Depreciation Factors w/updates of actuals through January 2024	1,431
W.	Non-Interest Bearing CWIP - Company CapEx position w/updates of actuals through January 2024	3,494
X.	Reflect O&M Tracking Adjustment in Working Capital	699
	Total Rate Base Adjustment	6,557

Capitalization Adjustments:		**Central Hudson Exceptions**
Y.	Common Equity Ratio	50%
	Return on Equity Cost Rate	9.8%

Central Hudson Gas & Electric Corporation
Net Gas Deferred Balances Available For Moderation

Description	Projected Balance @ July 1, 2025				
	Gross	FIT	FIT Contra	SIT	Net
Rate Moderator - Gas	(5,753,483)	1,208,200	(78,500)	374,000	(4,249,783)
Property Taxes - Gas	(4,393,329)	922,600	(60,000)	285,600	(3,245,129)
Pension Plan - Gas	(4,237,359)	889,800	(57,800)	275,400	(3,129,959)
Net Plant Target Shortfall - Case 20-G-0429 - Gas	(2,487,000)	522,300	(34,000)	161,700	(1,837,000)
Negative Revenue Adjustments - Gas	(2,518,800)	528,900	(34,400)	163,700	(1,860,600)
Energy Affordability Deferral - Gas	0	0	0	0	0
OPEB - Gas	(823,559)	172,900	(11,200)	53,500	(608,359)
Research & Development - Gas	(244,784)	51,400	(3,300)	15,900	(180,784)
Carrying Charges - Property Taxes - Gas	(170,605)	35,800	(2,300)	11,100	(126,005)
Economic Development	(326,844)	68,600	(4,500)	21,200	(241,544)
Carrying Charges - Rate Moderator - Gas	(211,628)	44,400	(2,900)	13,800	(156,328)
Sales Tax Refund/Assessment	(40,000)	8,400	(500)	2,600	(29,500)
Tax Rate Change - Other Plant - Gas	(2,926,000)	614,500	(39,900)	190,200	(2,161,200)
Carrying Charges - OPEB - Gas	(27,760)	5,800	(400)	1,800	(20,560)
Carrying Charges - Environmental SIR Costs & Recovery Deferral - Gas	(19,731)	4,100	(300)	1,300	(14,631)
Carrying Charges - Energy Affordability Program - Gas	(41,204)	8,700	(600)	2,700	(30,404)
Carrying Charges - Economic Development	(7,926)	1,700	(100)	500	(5,826)
Carrying Charges - Gas Reserve	(3,558)	700	0	200	(2,658)
Carrying Charges - Energy Efficiency	(17,877)	3,800	(300)	1,200	(13,177)
Carrying Charges - Sales Tax Refund/Assessment	(2,852)	600	0	200	(2,052)
Total Credits - Gas	(24,254,299)	5,093,200	(331,000)	1,576,600	(17,915,499)
Deferral of Interest - Gas	2,079,100	(436,600)	28,400	(135,100)	1,535,800
Gas Safety Transmission Final Rule	1,480,926	(311,000)	20,200	(96,300)	1,093,826
Leak Prone Pipe (LPP) - Gas Revenue Requirement	536,878	(112,700)	7,300	(34,900)	396,578
Uncollectible Write-Offs	2,545,243	(534,500)	34,700	(165,400)	1,880,043
Variable Rate Interest Undercollection - Gas	465,801	(97,800)	6,400	(30,300)	344,101
DEI Order 22-M-0314 - Gas	2,441	(500)	0	(200)	1,741
COVID Lost Revenue Deferral - Gas	582,239	(122,300)	7,900	(37,800)	430,039
Payment by Credit Card - Gas	303,529	(63,700)	4,100	(19,700)	224,229
Carrying Charges - Pension Plan - Gas	128,114	(26,900)	1,700	(8,300)	94,614
Carrying Charges - COVID Lost Revenues - Gas	61,224	(12,900)	800	(4,000)	45,124
Carrying Charges - Deferral of Interest - Gas	45,576	(9,600)	600	(3,000)	33,576
Carrying Charges - Leak Prone Pipe (LPP) - Gas Revenue Requirement	36,740	(7,700)	500	(2,400)	27,140
Carrying Charges - Gas Safety Transmission Final Rule	37,934	(8,000)	500	(2,500)	27,934
Carrying Charges - Gas Non Pipe Alternative	16,173	(3,400)	200	(1,100)	11,873
Carrying Charges - Variable Rate Interest - Gas	12,455	(2,600)	200	(800)	9,255
Carrying Charges - Uncollectible Write-Offs	38,355	(8,100)	500	(2,500)	28,255
Carrying Charges - Gas RAM	11,234	(2,400)	100	(700)	8,234
Carrying Charges - Payment by Credit Card - Gas	8,086	(1,700)	100	(500)	5,986
Carrying Charges - Management Audit Costs - Electric	3,833	(800)	0	(200)	2,833
Carrying Charges - DEI Order 22-M-0314 - Gas	71	0	0	0	71
Carrying Charges - Call Volume Overflow - Gas	733	(200)	0	0	533
Total Debits - Gas	8,396,685	(1,763,400)	114,200	(545,700)	6,201,785
Net Credit Available for Moderation after Offset - Gas	**(15,857,614)**	**3,329,800**	**(216,800)**	**1,030,900**	**(11,713,714)**

Appendix 3 - Recommended Decision
Schedule A Sheet 1 of 2
Cases 23-E-0418 & 23-G-0419
Central Hudson Gas & Electric Corporation
Electric Revenue Allocation

Twelve Months Ending June 30, 2025

	Min .75x, Max 1.25x	Rate Increase	Hydro Revenues	Total Rate increase
Incremental Revenue Requirement Excluding Taxes	(1)	$ 75,448,000	**$ 4,400,000**	**$ 79,848,000**
Percentage On Base Rates	(2)	**17.68%**		

	(3) Unitized Rate of Return Historic	(4) Unitized Rate of Return Information Only	(5) Unitized Rate of Return Pro Forma	(6) Revenue Allocation Factor	(7) RY Sales at Current Rates	(8)=(2)x(6)x(7) Base Rev Increase	(9) Adjustment **$ (731,071)**	(10)=(8)+(9) Total	(11) Revenue % Increase	(12) MFC Revenue from Current Base Rates	(13) Total Estimated MFC Revenue	(14)=(12)-(13) MFC Adjustment to Rate Increase	(15)=(10)+(14) Adj Base Rev Increase	(16) Hydro Revenues	(17) Adjusted Delivery Revenues	(18) Adj Increase as % of System	(19) Delivery Increase Percent
SC 1 Residential	0.88	0.88	1.08	**1.00**	$ 312,699,441	$ 55,300,053	$ (501,721)	$ 54,798,332	17.52%	$ 10,694,321	$ 7,129,562	$ 3,564,759	$ 58,363,091	$ (1,979,151)	$ 56,383,941	70.77%	18.67%
SC 2 Non Demand	0.63	0.79	0.49	**1.25**	$ 28,177,405	$ 6,228,873	$ (56,513)	$ 6,172,360	21.91%	$ 1,378,034	$ 916,688	$ 461,346	$ 6,633,706	$ (168,466)	$ 6,465,239	8.12%	24.12%
SC 2 Secondary	1.16	1.03	0.70	**1.00**	$ 76,380,468	$ 13,507,680	$ (122,551)	$ 13,385,129	17.52%	$ 432,628	$ 310,957	$ 121,671	$ 13,506,800	$ (1,181,125)	$ 12,325,675	15.47%	16.23%
SC 2 Primary	3.63	2.78	1.88	**0.75**	$ 6,809,674	$ 903,204	$ (8,195)	$ 895,010	13.14%	$ 6,720	$ 4,497	$ 2,223	$ 897,233	$ (187,493)	$ 709,740	0.89%	10.43%
SC 3 Primary	2.63	2.45	2.76	**0.75**	$ 9,052,558	$ 1,200,690	$ (10,894)	$ 1,189,797	13.14%	$ -	$ -	$ -	$ 1,189,797	$ (242,614)	$ 947,183	1.19%	10.46%
SC 5 Area Lighting	(0.48)	0.74	(0.05)	**1.25**	$ 2,756,300	$ 609,305	$ (5,528)	$ 603,777	21.91%	$ 168,680	$ 101,132	$ 67,548	$ 671,326	$ (10,617)	$ 660,709	0.83%	25.53%
SC 6 Residential TOU	1.63	1.91	1.09	**1.00**	$ 1,512,830	$ 267,540	$ (2,427)	$ 265,113	17.52%	$ 28,450	$ 31,067	$ (2,617)	$ 262,496	$ (11,508)	$ 250,988	0.32%	16.91%
SC 8 Street Lighting	3.94	3.31	2.50	**0.75**	$ 5,036,243	$ 667,985	$ (6,060)	$ 661,924	13.14%	$ 7,020	$ 5,751	$ 1,269	$ 663,193	$ (9,067)	$ 654,126	0.82%	13.01%
SC 9 Traffic Signals	1.21	(1.63)	19.59	**0.75**	$ 187,930	$ 24,926	$ (226)	$ 24,700	13.14%	$ 7,560	$ 1,613	$ 5,947	$ 30,647	$ (613)	$ 30,034	0.04%	16.65%
SC 13 Substation	2.56	2.43	0.96	**1.00**	$ 2,206,970	$ 390,297	$ (3,541)	$ 386,756	17.52%	$ -	$ -	$ -	$ 386,756	$ (91,559)	$ 295,197	0.37%	13.38%
SC 13 Transmission	0.50	1.85	0.14	**1.25**	$ 6,688,334	$ 1,478,517	$ (13,414)	$ 1,465,103	21.91%	$ -	$ -	$ -	$ 1,465,103	$ (517,787)	$ 947,316	1.19%	14.16%
Total	1.00	1.00	1.00		$ 451,508,153	$ 80,579,071	$ (731,071)	$ 79,848,000	17.68%	$ 12,723,413	$ 8,501,266	$ 4,222,147	$ 84,070,147	$ (4,400,000)	$ 79,670,147	100%	18.16%

Appendix 3 - Recommended Decision
Schedule A Sheet 2 of 2
Central Hudson Gas & Electric Corporation
Electric Energy Efficiency Base Rate Design
Cases 23-E-0418 & 23-G-0419
Twelve Months Ending June 30, 2025

	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	832,607		68.27%	8.67%	2,285,116		48.58%	42.41%	51.08%
SC 2 Non Demand	23,813		1.95%	0.25%	200,588		4.27%	3.72%	3.97%
SC 2 Secondary	276,044	1,746	22.49%	2.86%	1,351,986	8,903	28.56%	24.93%	27.78%
SC 2 Primary	27,676	716	2.21%	0.28%	224,829	3,526	4.71%	4.11%	4.39%
SC 3 Primary	34,374	1,212	2.72%	0.35%	283,101	6,381	5.88%	5.14%	5.48%
SC 5 Area Lighting	-		0.00%	0.00%	12,470		0.27%	0.23%	0.23%
SC 6 Residential TOU	2,728		0.22%	0.03%	13,220		0.28%	0.25%	0.27%
SC 8 Street Lighting	-		0.00%	0.00%	10,650		0.23%	0.20%	0.20%
SC 9 Traffic Signals	13		0.00%	0.00%	720		0.02%	0.01%	0.01%
SC 13 Substation	11,252	5,980	0.43%	0.05%	110,127	45,200	1.38%	1.20%	1.26%
SC 13 Transmission	67,240	46,510	1.70%	0.22%	627,338	352,583	5.84%	5.10%	5.32%
Total	1,275,747	56,164	100.00%	12.70%	5,120,145	416,592	100.00%	87.30%	100.00%

	Total	$ 6,569,000			**Non-RNY**	**Not**	**Non-RNY**	**Base Rates**	**Total**	**Recovery**				**Change**	**RY3**
	Allocator	**Allocation**	**All kW**	**RNY kW**	**kW**	**Collected**	**$/kW**	**$/kW**	**$/kW**	**All kW**	**RNY Credit**	**Total**	**Base Rate**	**from RY3**	**Base Rate**
SC 1 Residential	51.08%	$ 3,355,659										$ 3,355,659	$ 3,355,659	$ 970,652	$ 4,583,858
SC 2 Non Demand	3.97%	$ 260,880										$ 260,880	$ 260,880	$ 147,674	$ 360,880
SC 2 Secondary	27.78%	$ 1,825,188	4,184,672	20,952	4,163,720	$ 9,138	$ 0.002	$ 0.436	$ 0.438	$ 1,832,886	$ (9,177)	$ 1,823,709	$ 1,832,886	$ (690,098)	$ 3,054,633
SC 2 Primary	4.39%	$ 288,265	562,613	8,592	554,021	$ 4,402	$ 0.008	$ 0.512	$ 0.520	$ 292,559	$ (4,468)	$ 288,091	$ 292,559	$ (73,615)	$ 397,619
SC 3 Primary	5.48%	$ 360,058	641,624	14,544	627,080	$ 8,162	$ 0.013	$ 0.561	$ 0.574	$ 368,292	$ (8,348)	$ 359,944	$ 368,292	$ (176,611)	$ 586,933
SC 5 Area Lighting	0.23%	$ 15,197										$ 15,197	$ 15,197	$ 19,033	$ 20,391
SC 6 Residential TOU	0.27%	$ 17,983										$ 17,983	$ 17,983	$ (4,621)	$ 33,242
SC 8 Street Lighting	0.20%	$ 12,961										$ 12,961	$ 12,961	$ 17,510	$ 22,012
SC 9 Traffic Signals	0.01%	$ 869										$ 869	$ 869	$ 245	$ 1,615
SC 13 Substation	1.26%	$ 82,743	181,882	71,760	110,122	$ 32,646	$ 0.296	$ 0.455	$ 0.751	$ 136,593	$ (53,892)	$ 82,701	$ 136,593	$ (72,541)	$ 210,185
SC 13 Transmission	5.32%	$ 349,148	1,045,131	558,120	487,011	$ 186,452	$ 0.383	$ 0.334	$ 0.717	$ 749,359	$ (400,172)	$ 349,187	$ 749,359	$ (141,795)	$ 831,291
Total	100.00%	$ 6,568,951									$ (476,057)	$ 6,567,181	$ 7,043,238	$ (4,167)	$ 10,102,659

Appendix 3 - Recommended Decision
Schedule B
Central Hudson Gas & Electric Corporation
Cases 23-E 0418 & 23-G-0419
Gas Revenue Allocation - Twelve Months Ending June 30, 2025

Base Rate Increase		$	29,560,000
Incremental Revenue Requirement	(1)	**$**	**29,560,000**
Percentage On Base Rates	(2)		**21.75%**

Danskammer Imputation	$ 1,000,000
	-
Interruptible Imputation	$ 3,200,000
	-

	(3) Unitized Rate of Return Historic	(4) Unitized Rate of Return Information Only	(5) Unitized Rate of Return Pro Forma	(6) Revenue Allocation Factor	(7) RY Block Revs at Current Rates (Incl MFC)	(8)=(2)x(6)x(7) Base Rev Increase	(9) Adjustment $ 2,355,582	(10) Interruptible Imputation	(11) Danskammer Imputation	(12)=(8)+(9)+(10)+(11) Total
SC 1 & 12	1.16		1.18	0.75	$ 85,951,980	$ 14,023,415	$ 1,214,262.63	$ 2,038,131.56	$ 636,916.11	$ 17,912,725
SC 2, 6 & 13	0.43		0.80	1.25	$ 45,046,764	$ 12,249,271	$ 1,060,643	$ 1,068,168.88	$ 333,802.78	$ 14,711,885
SC 11 Transmission	3.68		4.50	0.75	$ 1,224,266	$ 199,744	$ 17,295	$ 29,030.35	$ 9,071.98	$ 255,142
SC 11 Distribution	0.92		-0.32	1.00	$ 1,543,372	$ 335,743	$ 29,071	$ 36,597.13	$ 11,436.60	$ 412,848
SC 11 - DLM	12.21		1.16	0.75	$ 1,183,854	$ 193,151	$ 16,725	$ 28,072.07	$ 8,772.52	$ 246,720
SC 11 - EG (Excl Danskammer)	0.00		0.00	1.00	$ 933,600	$ 203,094	$ 17,586	$ -	$ -	$ 220,680
Total					135,883,836	$ 27,204,418	$ 2,355,582	$ 3,200,000	$ 1,000,000	$ 33,760,000

	(13) Revenue % Increase	(14) MFC Revenue from Current MFC Rates	(15) Total Estimated MFC Revenue	(16)=(14)-(15) MFC Adjustment to Rate Increase	(17)=(12)+(16) Adj Base Rev Increase	(18) Interruptible Revenues	(19) Danskammer Revenues	(20)=(7)+(17)+(18)+(19) Adjusted Delivery Revenues	(21) Adj Increase as % of System	(22) Delivery Increase Percent
SC 1 & 12	20.84%	$ 983,140	$ 1,014,763	$ (31,623)	$ 17,881,102	$ (2,038,131.56)	$ (636,916.11)	$ 101,158,034	53.15%	17.69%
SC 2, 6 & 13	32.66%	$ 1,265,192	$ 1,351,960	$ (86,768)	$ 14,625,117	$ (1,068,168.88)	$ (333,802.78)	$ 58,269,909	43.47%	29.35%
SC 11 Transmission	20.84%	$ -	$ -	$ -	$ 255,142	$ (29,030.35)	$ (9,071.98)	$ 1,441,306	0.76%	17.73%
SC 11 Distribution	26.75%	$ -	$ -	$ -	$ 412,848	$ (36,597.13)	$ (11,436.60)	$ 1,908,187	1.23%	23.64%
SC 11 - DLM	20.84%	$ -	$ -	$ -	$ 246,720	$ (28,072.07)	$ (8,772.52)	$ 1,393,729	0.74%	17.73%
SC 11 - EG (Excl Danskammer)	23.64%	$ -	$ -	$ -	$ 220,680	$ -	$ -	$ 1,154,279.74	0.66%	23.64%
Total		$ 2,248,332	$ 2,366,723	$ (118,391)	$ 33,641,609	$ (3,200,000)	$ (1,000,000)	$ 165,325,446	100.00%	25.17%

Energy Efficiency Allocation	(23) RY Billing Determinants	(24) EE Change in Allocation	(25) = (17)+(24) Adj Base Rev Increase Incl EE	Interruptible Revenues	Adjusted Delivery Revenues	Adj Increase as % of System	Delivery Increase Percent
SC 1 & 12	5,646,985	$ 178,348	$ 18,059,450	$ (2,038,132)	$ 101,973,299	53.68%	18.64%
SC 2, 6 & 13	7,548,630	$ (164,098)	$ 14,461,019	$ (1,068,169)	$ 58,439,614	42.99%	29.73%
SC 11 Transmission	861,148	$ 3,682	$ 258,824	$ (29,030)	$ 1,454,060	0.77%	18.77%
SC 11 Distribution	561,693	$ (3,290)	$ 409,559	$ (36,597)	$ 1,916,334	1.22%	24.17%
SC 11 - DLM	664,566	$ 1,341	$ 248,060	$ (28,072)	$ 1,403,842	0.74%	18.58%
SC 11 - EG (Excl Danskammer)	60,000	$ (15,983)	$ 204,697	$ -	$ 1,138,297	0.61%	21.93%
Total	15,343,022	$ 0	$ 33,641,609	$ (3,200,000)	$ 166,325,446	100.00%	22.40%

* Estimated billing determinants for Energy Efficiency allocation purposes only - reflects most recent 3 year annual average

$ 1,939,000.00	2023 EET Alloc.				
SC 1/12	$ 985,752	**71.4%**	SC 1 & 12	$ 1,384,021	
SC 2/6/11/13	$ 395,277	**28.6%**	SC 2, 6 & 13	$ 432,066	
	$ 1,381,029		SC 11 Transmissi	$ 49,290	
			SC 11 Distribution	$ 32,150	
			SC 11 - DLM	$ 38,038	
			SC 11 - EG (Excl I	$ 3,434	
			Total	$ 1,939,000	

					Change
$ 1,265,000.00	2020 EET Alloc.				
SC 1/12	$ 682,000	**61.6%**	SC 1 & 12	$ 779,341	$ 604,680
SC 2/6/11/13	$ 425,000	**38.4%**	SC 2, 6 & 13	$ 372,727	$ 59,340
	$ 1,107,000		SC 11 Transmissi	$ 39,536	$ 9,754
			SC 11 Distribution	$ 27,785	$ 4,366
			SC 11 - DLM	$ 30,826	$ 7,213
			SC 11 - EG (Excl I	$ 14,787	$ (11,352)
			Total	$ 1,265,000	

$ (674,000.00)	2023 EET Alloc.				
SC 1/12	$ 985,752	**63.3%**	SC 1 & 12	$ (426,332)	$ 178,348
SC 2/6/11/13	$ 395,277	**33.2%**	SC 2, 6 & 13	$ (223,437)	$ (164,098)
	$ 1,381,029	**0.9%**	SC 11 Transmissi	$ (6,073)	$ 3,682
		1.1%	SC 11 Distribution	$ (7,655)	$ (3,290)
		0.9%	SC 11 - DLM	$ (5,872)	$ 1,341
		0.7%	SC 11 - EG (Excl I	$ (4,631)	$ (15,983)
			Total	$ (674,000)	

UNITIZED RATE OF RETURN
Pro Forma

Pro Forma ECOS	3.74%	TOTAL	1.00	
SC 1 & 12	4.43%	SC 1 & 12	1.18	High
SC 2, 6 & 13	2.99%	SC 2, 6 & 13	0.80	Low
SC 11 Transmission	16.84%	SC 11 Transmission	4.50	High
SC 11 Distribution	-1.19%	SC 11 Distribution	(0.32)	Low
SC 11 - DLM	4.35%	SC 11 - DLM	1.16	High

UNITIZED RATE OF RETURN
Embedded

Historic ECOS	5.59%	TOTAL	1.00	
SC 1 & 12	6.48%	SC 1 & 12	1.16	High
SC 2, 6 & 13	2.40%	SC 2, 6 & 13	0.43	Low
SC 11 Transmission	20.59%	SC 11 Transmission	3.68	High
SC 11 Distribution	5.14%	SC 11 Distribution	0.92	
SC 11 - DLM	68.25%	SC 11 - DLM	12.21	High

UNITIZED RATE OF RETURN
Hypothetical

Hypothetical ECOS	4.07%	TOTAL	1.00	
SC 1 & 12	4.37%	SC 1 & 12	1.07	
SC 2, 6 & 13	3.23%	SC 2, 6 & 13	0.79	Low
SC 11 Transmission	7.71%	SC 11 Transmission	1.89	High
SC 11 Distribution	0.21%	SC 11 Distribution	0.05	Low
SC 11 - DLM	3.29%	SC 11 - DLM	0.81	Low

Appendix 3 - Recommended Decision
Schedule C Sheet 1 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Proposed Monthly Electric Base Delivery Rates
(Excludes S.C. Nos. 5 & 8, Unbilled & Interdepartmental)

		Current Rates	12 Months Ending Jun-25 Rate Year
S.C. No. 1			
	Customer Charge	$ 19.50	$ 21.50
	kWh Delivery	$ 0.10546	$ 0.12782
S.C. No. 2 - Non-Demand			
	Customer Charge	$ 30.50	$ 32.50
	kWh Delivery	$ 0.07234	$ 0.10129
S.C. No. 2 - Secondary			
	Customer Charge	$ 120.00	$ 140.00
	HPP Customer Charge	$ 150.00	$ 170.00
	kWh Delivery	$ 0.00467	$ 0.00467
	kW Delivery	$ 12.71	$ 14.84
	Rkva*	$ 0.83	$ 0.83
S.C. No. 2 - Primary			
	Customer Charge	$ 490.00	$ 530.00
	HPP Customer Charge	$ 520.00	$ 560.00
	kWh Delivery	$ 0.00144	$ 0.00144
	kW Delivery	$ 9.79	$ 10.79
	Rkva*	$ 0.83	$ 0.83
S.C. No. 3			
	Customer Charge	$ 2,400.00	$ 2,600.00
	kWh Delivery	$ -	$ -
	kW Delivery	$ 12.56	$ 13.64
	Rkva	$ 0.83	$ 0.83
S.C. No. 6			
	Customer Charge	$ 22.50	$ 24.50
	kWh Delivery On Pk	$ 0.13836	$ 0.16303
	kWh Delivery Off Pk	$ 0.04612	$ 0.05434
S.C. No. 6 (5 Hour On-Peak)			
	Customer Charge	$ 22.50	$ 24.50
	kWh Delivery On Pk	$ 0.10987	$ 0.13513
	kWh Delivery Off Pk	$ 0.09501	$ 0.11685
S.C. No. 9			
	Signal Faces	$ 4.26	$ 4.98
S.C. No. 13 - Substation			
	Customer Charge	$ 7,500.00	$ 8,500.00
	kWh Delivery	$ -	$ -
	kW Delivery	$ 10.11	$ 11.03
	Rkva	$ 0.83	$ 0.83
S.C. No. 13 - Transmission			
	Customer Charge	$ 12,000.00	$ 13,500.00
	kWh Delivery	$ -	$ -
	kW Delivery	$ 5.95	$ 6.62
	Rkva	$ 0.83	$ 0.83

Energy Efficiency Exemption Credit Rate per kW:		
	S.C. No. 2 - Secondary	$ 0.44
	S.C. No. 2 - Primary	$ 0.52
	S.C. No. 3	$ 0.57
	S.C. No. 13 - Substation	$ 0.75
	S.C. No. 13 - Transmission	$ 0.72

*As applicable

Appendix 3 - Recommended Decision
Schedule C Sheet 2 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates
Area Lighting

Service Classification No. 5 - P.S.C. No. 15

Lamp and Fixture Charge

Lumens	Type	Annual kWh	Present Monthly Base Rate	Proposed Monthly Base Rate
First Light				
7,000	Mercury	832	$15.32	$19.10
20,000	Mercury	1,820	$21.43	$26.71
60,000	Mercury	4,320	$35.40	$44.13
5,800	Sodium	344	$12.90	$16.08
16,000	Sodium	721	$15.74	$19.62
27,000	Sodium	1,264	$19.60	$24.43
50,000	Sodium	1,984	$23.44	$29.22
140,000	Sodium	4,656	$41.75	$52.05
50,000	Sodium - Floodlight	1,984	$23.99	$29.91
20,500	Metal Halide	1,200	$19.76	$24.63
36,000	Metal Halide	1,856	$22.45	$27.99
36,000	Metal Halide - Floodlight	1,856	$23.18	$28.90
110,000	Metal Halide - Floodlight	4,400	$39.20	$48.87
14,001	Metal Halide (P)	820	$43.66	$54.43
20,501	Metal Halide (P)	1,200	$51.37	$64.04
36,001	Metal Halide	1,856	$61.29	$76.40
5,801	Sodium Vapor (P)	344	$26.55	$33.10
2,900	LED	100	$15.62	$19.47
6,800	LED	260	$16.37	$20.41
9,500	LED	380	$18.74	$23.36
16,500	LED	620	$24.90	$31.04
3,000	LED	120	$11.73	$14.62
2,000	LED	80	$13.11	$16.34
5,250	LED	212	$13.73	$17.12
7,500	LED	300	$15.73	$19.61
13,000	LED	520	$20.89	$26.04
17,750	LED	712	$25.32	$31.56
27,500	LED	1100	$31.29	$39.01
1,500	LED	60	$18.43	$22.98
2,500	LED	100	$27.98	$34.88
8,000	LED	320	$22.58	$28.15
15,250	LED	612	$31.56	$39.34
25,750	LED	1032	$38.65	$48.18
12,000	LED	480	$63.19	$78.77
16,001	LED	640	$52.84	$65.87

Lamp, Fixture and Pole Package Charge

Lumens	Type	Annual kWhrs	Present Monthly Base Rate	Proposed Monthly Base Rate
14,000	Metal Halide	820	$43.66	$54.43
20,500	Metal Halide	1,200	$51.37	$64.04
36,000	Metal Halide	1,856	$61.29	$76.40
5,800	Sodium - Colonial Post Top	344	$26.55	$33.10

Appendix 3 - Recommended Decision
Schedule C Sheet 3 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates
Area Lighting

Service Classification No. 5 - P.S.C. No. 15

Decorative and Specialty Lighting

Lumens	Type	Annual kWhrs	Present Monthly Base Rate	Proposed Monthly Base Rate
5,800	Sodium - Acorn	344	$20.52	$25.58
6,000	Induction - Acorn	340	$26.99	$33.65
14,000	Metal Halide - Acorn	820	$20.49	$25.54
16,000	Sodium - Victorian	721	$21.22	$26.45
27,000	Sodium - Highway Setback	1,264	$19.41	$24.20
50,000	Sodium - Highway Setback	1,984	$18.17	$22.65
20,500	Metal Halide - Highway Setback	1,200	$21.51	$26.81
36,000	Metal Halide - Highway Setback	1,856	$24.30	$30.29
27,000	Sodium - Teardrop	1,264	$36.58	$45.60
50,000	Sodium - Teardrop	1,984	$40.87	$50.95
20,500	Metal Halide - Teardrop	1,200	$37.95	$47.31
36,000	Metal Halide - Teardrop	1,856	$40.96	$51.06

Decorative and Specialty Lighting - Supporting Equipment

Type	Present Monthly Base Rate	Proposed Monthly Base Rate
Standard Wooden Utility Pole	$12.67	$15.79
Fluted Decorative Fiberglass Pole (area lighting)	$41.39	$51.60
Fiberglass Pole up to 20' (decorative other than highway)	$36.64	$45.68
Fiberglass Pole for Highway Setback (30' mounting height)	$36.64	$45.68
Decorative Arm for Decorative Teardrop Lighting	$17.61	$21.95

Appendix 3 - Recommended Decision
Schedule C Sheet 4 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates
Public Street and Highway Lighting

Service Classification No. 8 - P.S.C. No. 15

Company Owned and Maintained

Lumens	Type	Annual kWh	Present Annual Base Rate	Proposed Annual Base Rate
Standard Lights				
5,800	Sodium Vapor	344	$231.79	$262.70
16,000	Sodium Vapor	720	$257.62	$291.98
27,000	Sodium Vapor	1,264	$312.37	$354.03
50,000	Sodium Vapor	1,984	$352.25	$399.23
140,000	Sodium Vapor	4,656	$583.31	$661.10
20,500	Metal Halide	1,200	$355.35	$402.74
36,000	Metal Halide	1,856	$344.85	$390.84
LED Lights				
3,600	LED	156	$183.58	$208.06
7,200	LED	328	$207.94	$235.67
10,000	LED	372	$252.94	$286.67
17,600	LED	612	$374.64	$424.60
2,900	LED	100	$187.88	$212.94
6,800	LED	260	$196.71	$222.94
9,500	LED	380	$225.30	$255.35
16,500	LED	620	$299.15	$339.04
3,000	LED	120	$141.37	$160.22
2,000	LED	80	$160.97	$182.44
5,250	LED	212	$168.53	$191.01
7,500	LED	300	$193.04	$218.78
13,000	LED	520	$256.31	$290.49
17,750	LED	712	$305.17	$345.87
27,500	LED	1,100	$377.04	$427.32
Non-Standard Lights				
1,000	Incandescent	368	$187.12	$212.07
2,500	Incandescent	756	$247.50	$280.51
4,000	Incandescent	1,180	$296.95	$336.55
6,000	Incandescent	1,620	$340.19	$385.56
3,600	Mercury Vapor	504	$238.12	$269.88
7,000	Mercury Vapor	832	$257.86	$292.25
11,000	Mercury Vapor	1,184	$279.73	$317.03
15,000	Mercury Vapor	1,820	$326.36	$369.88
20,000	Mercury Vapor	1,820	$326.36	$369.88
60,000	Mercury Vapor	4,320	$478.82	$542.68
Lamp, Fixture and Pole Package				
5,800	Sodium Vapor - Colonial Post Top	344	$501.65	$568.55
5,800	Sodium Vapor	344	$632.39	$716.73
16,000	Sodium Vapor	720	$655.51	$742.93
14,000	Metal Halide	820	$722.52	$818.88
20,500	Metal Halide	1,200	$746.73	$846.31
36,000	Metal Halide	1,856	$790.71	$896.16
Standard Decorative and Special Purpose Luminaires				
5,800	Sodium Vapor - Acorn	344	$293.26	$332.37
6,000	Induction - Acorn	340	$397.77	$450.82
14,000	Metal Halide - Acorn	820	$371.15	$420.65
16,000	Sodium Vapor - Victorian	720	$377.88	$428.27
27,000	Sodium Vapor - Highway Setback	1,264	$358.56	$406.38
50,000	Sodium Vapor - Highway Setback	1,984	$403.13	$456.89
20,500	Metal Halide - Highway Setback	1,200	$410.82	$465.61
36,000	Metal Halide - Highway Setback	1,856	$400.07	$453.42
50,000	Sodium Vapor - Floodlight	1,984	$373.08	$422.83
36,000	Metal Halide - Floodlight	1,856	$357.58	$405.27
110,000	Metal Halide - Floodlight	4,400	$614.27	$696.19
27,000	Sodium Vapor - Teardrop	1,264	$431.97	$489.58
50,000	Sodium Vapor - Teardrop	2,480	$506.72	$574.30
20,500	Metal Halide - Teardrop	1,200	$468.06	$530.48
36,000	Metal Halide - Teardrop	1,856	$479.80	$543.79
1,500	LED	60	$221.96	$251.56
2,500	LED	100	$337.09	$382.04
8,000	LED	320	$272.06	$308.34
15,250	LED	612	$380.33	$431.05
25,750	LED	1,032	$465.79	$527.91
12,000	LED	480	$761.46	$863.01
16,001	LED	640	$636.71	$721.62

Appendix 3 - Recommended Decision
Schedule C Sheet 5 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates
Public Street and Highway Lighting

Service Classification No. 8 - P.S.C. No. 15

Customer Owned/Company Maintained

Lumens	Type	Annual kWh	Present Annual Base Rate	Proposed Annual Base Rate
Standard Lights				
6,000	Induction	340	$69.07	$78.28
5,800	Sodium Vapor	344	$78.76	$89.26
16,000	Sodium Vapor	720	$101.30	$114.81
27,000	Sodium Vapor	1,264	$133.88	$151.73
50,000	Sodium Vapor	1,984	$177.64	$201.33
140,000	Sodium Vapor	4,656	$347.60	$393.96
14,000	Metal Halide	820	$114.76	$130.06
20,500	Metal Halide	1,200	$138.70	$157.20
36,000	Metal Halide	1,856	$174.01	$197.22
108,000	Metal Halide	4,400	$370.22	$419.59
Non-Standard Lights				
9,500	Sodium Vapor	584	$93.16	$105.58
1,000	Incandescent	368	$115.59	$131.01
2,500	Incandescent	756	$153.23	$173.66
4,000	Incandescent	1,180	$180.09	$204.11
6,000	Incandescent	1,620	$233.80	$264.98
10,000	Incandescent	2,480	$285.37	$323.43
7,000	Mercury Vapor	832	$106.86	$121.11
11,000	Mercury Vapor	1,184	$128.53	$145.67
15,000	Mercury Vapor	1,820	$172.44	$195.44
20,000	Mercury Vapor	1,820	$172.44	$195.44
60,000	Mercury Vapor	4,320	$324.01	$367.22

Other Charges

Type	Present Base Rate	Proposed Base Rate
Pre-attachment survey fee	$12.69	$14.38
Annual pole rental (solely for street lighting)	$86.69	$98.25
Annual pole rental (company sole owned)	$9.94	$11.27
Annual pole rental (company joint owned)	$4.95	$5.61

Appendix 3 - Recommended Decision
Schedule C Sheet 6 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates
Public Street and Highway Lighting

Service Classification No. 8 - P.S.C. No. 15

Company Owned and Maintained

Lumens	Type	Annual kWh	Present Annual Base Rate	Proposed Annual Base Rate
Standard Lights				
5,800	Sodium Vapor	344	$34.98	$39.64
9,500	Sodium Vapor	584	$49.41	$56.00
16,000	Sodium Vapor	720	$57.55	$65.22
27,000	Sodium Vapor	1,264	$90.17	$102.20
50,000	Sodium Vapor	1,984	$133.32	$151.10
140,000	Sodium Vapor	4,656	$293.50	$332.64
8,500	Metal Halide	520	$45.56	$51.64
14,000	Metal Halide	820	$63.57	$72.05
20,500	Metal Halide	1,200	$86.34	$97.85
36,000	Metal Halide	1,856	$125.62	$142.37
110,000	Metal Halide	4,400	$278.18	$315.28
Non-Standard Lights				
1,000	Incandescent	368	$36.43	$41.29
2,500	Incandescent	756	$59.73	$67.70
4,000	Incandescent	1,180	$85.13	$96.48
6,000	Incandescent	1,620	$111.53	$126.40
3,600	Mercury Vapor	504	$44.58	$50.53
7,000	Mercury Vapor	832	$64.26	$72.83
11,000	Mercury Vapor	1,184	$85.40	$96.79
20,000	Mercury Vapor	1,820	$123.50	$139.97
60,000	Mercury Vapor	4,320	$273.49	$309.96
6,000	Induction	340	$34.75	$39.38

Other Charges

Type	Present Base Rate	Proposed Base Rate
Pre-attachment survey fee	$12.69	$14.38
Annual pole rental (solely for street lighting)	$86.69	$98.25
Annual pole rental (company sole owned)	$9.94	$11.27
Annual pole rental (company joint owned)	$4.95	$5.61

Public Street and Highway Lighting - Supporting Equipment

Type	Present* Base Rate	Proposed Base Rate
Standard Company Pole (street lighting)	$ 86.69	$ 98.25
Mastarms greater than 14'	$ 48.97	$ 55.50
Fluted Decorative Fiberglass Pole	$ 452.83	$ 513.22
Fiberglass Pole up to 20' (decorative lighting)	$ 401.34	$ 454.86
Fiberglass Pole for Highway Setback (30' mounting height)	$ 401.34	$ 454.86
Decorative Arm for Decorative Teardrop Lighting	$ 192.73	$ 218.43

Appendix 3 - Recommended Decision
Schedule C Sheet 7 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Proposed Electric Merchant Function Charges

	Current Rates	12 Months Ending Jun-25 Rate Year
MFC Administration Charge per kWh		
S.C. No. 1 - Residential	$ 0.00142	$ 0.00092
S.C. No. 2 - Non Demand	$ 0.00209	$ 0.00134
S.C. No. 2 - Primary Demand	$ 0.00001	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00010	$ 0.00007
S.C. No. 3 - Large Power Primary	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00411	$ 0.00238
S.C. No. 6 - Residential Time-of-Use	$ 0.00065	$ 0.00069
S.C. No. 8 - Street Lighting	$ 0.00020	$ 0.00016
S.C. No. 9 - Traffic Signals	$ 0.00319	$ 0.00066
S.C. No. 13 - Substation	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -
MFC Supply Charge per kWh		
S.C. No. 1 - Residential	$ 0.00326	$ 0.00220
S.C. No. 2 - Non Demand	$ 0.00478	$ 0.00323
S.C. No. 2 - Primary Demand	$ 0.00002	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00022	$ 0.00016
S.C. No. 3 - Large Power Primary	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00941	$ 0.00573
S.C. No. 6 - Residential Time-of-Use	$ 0.00150	$ 0.00166
S.C. No. 8 - Street Lighting	$ 0.00046	$ 0.00038
S.C. No. 9 - Traffic Signals	$ 0.00731	$ 0.00158
S.C. No. 13 - Substation	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -

Appendix 3 - Recommended Decision
Schedule C Sheet 8 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Low Income Bill Discount Program Credits

	Electric Heating		Electric Non-Heating	
Income Level	**Current**	**Proposed**	**Current**	**Proposed**
Tier 1	$ 42.91	$ 63.84	$ 42.91	$ 63.84
Tier 2	$ 54.04	$ 74.97	$ 54.04	$ 74.97
Tier 3	$ 73.61	$ 94.53	$ 73.61	$ 94.53
Tier 4	$ 67.75	$ 88.68	$ 67.75	$ 88.68

Appendix 3 - Recommended Decision
Schedule C Sheet 9 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
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	Proposed Rates	
S.C. No. 1				
	Customer Charge	$ 19.50	$ 21.50	
	Contract Demand	$ 5.58	$ 4.72	per kW
	Daily As-Used Demand On-Peak	$ 0.42583	$ 0.51342	per kW
	Daily As-Used Demand Super-Peak	$ 0.17846	$ 0.19867	
S.C. No. 2 - Non Demand				
	Customer Charge	$ 30.50	$ 32.50	
	Contract Demand	$ 4.81	$ 7.61	per kW
	Daily As-Used Demand On-Peak	$ 0.42436	$ 0.44239	per kW
	Daily As-Used Demand Super-Peak	$ 0.14621	$ 0.19854	per kW
S.C. No. 2 - Secondary Demand				
	Customer Charge	$ 120.00	$ 140.00	
	Contract Demand	$ 1.97	$ 1.49	per kW
	Daily As-Used Demand On-Peak	$ 0.54396	$ 0.63948	per kW
	Daily As-Used Demand Super-Peak	$ 0.13960	$ 0.21633	per kW
S.C. No. 2 - Primary Demand				
	Customer Charge	$ 490.00	$ 530.00	
	Contract Demand	$ 3.15	$ 3.13	per kW
	Daily As-Used Demand On-Peak	$ 0.35017	$ 0.41674	per kW
	Daily As-Used Demand Super-Peak	$ 0.09804	$ 0.13162	per kW
S.C. No. 3				
	Customer Charge	$ 2,400.00	$ 2,600.00	
	Contract Demand	$ 3.52	$ 4.35	per kW
	Daily As-Used Demand On-Peak	$ 0.49173	$ 0.48507	per kW
	Daily As-Used Demand Super-Peak	$ 0.17971	$ 0.14928	per kW
S.C. No. 6				
	Customer Charge	$ 22.50	$ 24.50	
	Contract Demand	$ 5.89	$ 4.15	per kW
	Daily As-Used Demand On-Peak	$ 0.61821	$ 0.51456	per kW
	Daily As-Used Demand Super-Peak	$ 0.27940	$ 0.19977	
S.C. No. 13 - Substation				
	Customer Charge	$ 7,500.00	$ 8,500.00	
	Contract Demand	$ 0.98	$ 3.24	per kW
	Daily As-Used Demand On-Peak	$ 0.30770	$ 0.37007	per kW
	Daily As-Used Demand Super-Peak	$ 0.11298	$ 0.11750	per kW
S.C. No. 13 - Transmission				
	Customer Charge	$ 12,000.00	$ 13,500.00	
	Contract Demand	$ 1.17	$ 2.25	per kW
	Daily As-Used Demand On-Peak	$ 0.17589	$ 0.21152	per kW
	Daily As-Used Demand Super-Peak	$ 0.06002	$ 0.07043	per kW

Appendix 3 - Recommended Decision
Schedule D Sheet 1 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Proposed Monthly Gas Base Delivery Rates

			Current Rates	12 Months Ending Jun-25 Rate Year
S.C. No. 1 & 12				
	Billing Block 1	First 2 Ccf	$ 24.25	$ 26.25
	Billing Block 2 per Ccf	Next 48 Ccf	$ 1.3625	$ 1.5141
	Billing Block 3 per Ccf	Additional	$ 0.9479	$ 1.2835
S.C. No. 2, 6 & 13				
	Billing Block 1	First 2 Ccf	$ 39.00	$ 41.00
	Billing Block 2 per Ccf	Next 98 Ccf	$ 0.5609	$ 0.7090
	Billing Block 3 per Ccf	Next 4900 Ccf	$ 0.5420	$ 0.6971
	Billing Block 4 per Ccf	Additional	$ 0.4805	$ 0.6575
	SC 6 High Volume	All Ccf above 2 Ccf	$ 0.3869	$ 0.5945
S.C. No. 11 Transmission	Customer Charge	First 1,000 Ccf	$ 4,800.00	$ 4,000.00
	Volumetric Charge per Ccf	Additional	$ 0.0189	$ 0.0231
	MDQ	Per Mcf of MDQ per Month	$ 9.23	$ 11.22
S.C. No. 11 Distribution	Customer Charge	First 1,000 Ccf	$ 2,100.00	$ 2,400.00
	Volumetric Charge per Ccf	Additional	$ 0.0404	$ 0.0500
	MDQ	Per Mcf of MDQ per Month	$ 21.35	$ 26.50
S.C. No. 11 DLM	Customer Charge	First 1,000 Ccf	$ 7,600.00	$ 7,100.00
	Volumetric Charge per Ccf	Additional	$ 0.0275	$ 0.0347
	MDQ	Per Mcf of MDQ per Month	$ 15.48	$ 18.36
S.C. No. 11 EG	Customer Charge		$ 2,000.00	$ 3,000.00
	MDQ	Per Mcf of MDQ per Month	$ 15.16	$ 18.37

Appendix 3 - Recommended Decision
Schedule D Sheet 2 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E 0418 & 23-G-0419
Gas Commodity Related Merchant Function Charges
Twelve Months Ending June 30, 2025

		Current Rates	Proposed
MFC Administration Charge per Ccf			
MFC-1	1, 12 & 16	$ 0.00533	$ 0.00484
MFC-2	2, 6, 13 & 15	$ 0.00513	$ 0.00483
MFC Supply Charge per Ccf			
MFC-1	1, 12 & 16	$ 0.01208	$ 0.01313
MFC-2	2, 6, 13 & 15	$ 0.01163	$ 0.01308

Appendix 3 - Recommended Decision
Schedule D Sheet 3 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Low Income Bill Discount Program Credits
Twelve Months Ended June 30, 2025

	Gas Heating		Gas Non-Heating	
Income Level	**Current**	**Proposed**	**Current**	**Proposed**
Tier 1	$ 22.99	$ 28.74	$ 3.00	$ 3.00
Tier 2	$ 42.68	$ 54.11	$ 3.00	$ 3.00
Tier 3	$ 57.48	$ 73.67	$ 3.00	$ 3.00
Tier 4	$ 51.76	$ 67.82	$ 3.00	$ 3.00

Appendix 3 - Recommended Decision
Schedule E Sheet 1 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Electric Residential Typical Monthly Bill

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Avg kWh	**660**	**660**	**570**	**570**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 19.50	$ 21.50	$ 19.50	$ 21.50	
Energy Delivery $/kWh					
Delivery Chrg	$0.10546	$0.12782	$0.10546	$0.12782	
System Benefits Chrg	$0.00866	$0.00866	$0.00866	$0.00866	
MFC Admin Chrg	$0.00142	$0.00092	$0.00142	$0.00092	
Transition Adj Chrg	$0.00010	$0.00010	$0.00010	$0.00010	
Electric Bill Credit	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous II	$0.00731	$0.00731	$0.00731	$0.00731	
Purchased Power Adjustment	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous Charges	$0.00103	$0.00103	$0.00103	$0.00103	
MFC Supply Chrg	$0.00337	$0.00231	$0.00337	$0.00231	
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	$19.95	$22.00	$19.95	$22.00	
Energy Delivery					
Delivery	$71.21	$86.31	$61.50	$74.54	
MFC Admin Chrg	$0.96	$0.62	$0.83	$0.54	
Transition Adj Chrg	$0.07	$0.07	$0.06	$0.06	
EBC	$0.00	$0.00	$0.00	$0.00	
SBC	$5.85	$5.85	$5.05	$5.05	
Delivery Subtotal w/ Revenue Tax	$98.04	$114.85	$87.39	$102.19	
Energy Supply					
PPA	$0.00	$0.00	$0.00	$0.00	
MISC	$5.62	$5.62	$4.85	$4.85	
MPC	$56.74	$56.74	$49.00	$49.00	
MPA	($1.47)	($1.47)	($1.27)	($1.27)	
MFC Supply Chrg	$2.28	$1.56	$1.97	$1.35	
Energy Subtotal w/ Revenue Tax	$63.17	$62.45	$54.55	$53.93	
Low Income Bill Discount	$0.00	$0.00	$ (42.91)	$ (63.84)	(Tier 1 Discount)
Total Bill	**$161.21**	**$177.30**	**$99.03**	**$92.28**	

$ Total Delivery Increase	$16.09	($6.75)
% Total Delivery Increase	17.03%	-16.30%
$ Total Bill Increase	$16.09	($6.75)
% Total Bill Increase	9.98%	-6.82%

Appendix 3 - Recommended Decision
Schedule E Sheet 2 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Electric Residential Typical Monthly Bill

Delivery Only				
Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
3	$ 20.33	$ 22.44	$ 2.11	10.4%
10	$ 21.22	$ 23.49	$ 2.27	10.7%
20	$ 22.49	$ 24.98	$ 2.49	11.1%
30	$ 23.76	$ 26.47	$ 2.72	11.4%
40	$ 25.02	$ 27.96	$ 2.94	11.8%
50	$ 26.29	$ 29.46	$ 3.16	12.0%
80	$ 30.10	$ 33.93	$ 3.84	12.7%
90	$ 31.36	$ 35.42	$ 4.06	12.9%
100	$ 32.63	$ 36.92	$ 4.28	13.1%
125	$ 35.80	$ 40.65	$ 4.84	13.5%
150	$ 38.97	$ 44.37	$ 5.40	13.9%
175	$ 42.14	$ 48.10	$ 5.96	14.1%
200	$ 45.31	$ 51.83	$ 6.52	14.4%
250	$ 51.66	$ 59.29	$ 7.64	14.8%
300	$ 58.00	$ 66.75	$ 8.76	15.1%
350	$ 64.34	$ 74.21	$ 9.87	15.3%
400	$ 70.68	$ 81.67	$ 10.99	15.6%
500	$ 83.36	$ 96.59	$ 13.23	15.9%
750	$ 115.07	$ 133.89	$ 18.82	16.4%
1,000	$ 146.77	$ 171.18	$ 24.41	16.6%
1,500	$ 210.18	$ 245.78	$ 35.59	16.9%
2,000	$ 273.60	$ 320.37	$ 46.78	17.1%
3,000	$ 400.42	$ 469.56	$ 69.14	17.3%
5,000	$ 654.06	$ 767.93	$ 113.87	17.4%
10,000	$ 1,288.18	$ 1,513.87	$ 225.70	17.5%

Total Bill				
Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
3	$ 20.59	$ 22.70	$ 2.11	10.2%
10	$ 22.09	$ 24.35	$ 2.26	10.2%
20	$ 24.23	$ 26.70	$ 2.47	10.2%
30	$ 26.37	$ 29.06	$ 2.68	10.2%
40	$ 28.51	$ 31.41	$ 2.90	10.2%
50	$ 30.65	$ 33.76	$ 3.11	10.1%
80	$ 37.07	$ 40.82	$ 3.75	10.1%
90	$ 39.21	$ 43.17	$ 3.96	10.1%
100	$ 41.35	$ 45.53	$ 4.17	10.1%
125	$ 46.70	$ 51.41	$ 4.71	10.1%
150	$ 52.05	$ 57.29	$ 5.24	10.1%
175	$ 57.40	$ 63.17	$ 5.77	10.1%
200	$ 62.75	$ 69.06	$ 6.30	10.0%
250	$ 73.45	$ 80.82	$ 7.37	10.0%
300	$ 84.15	$ 92.58	$ 8.43	10.0%
350	$ 94.85	$ 104.35	$ 9.49	10.0%
400	$ 105.56	$ 116.11	$ 10.56	10.0%
500	$ 126.96	$ 139.64	$ 12.69	10.0%
750	$ 180.46	$ 198.47	$ 18.01	10.0%
1,000	$ 233.96	$ 257.29	$ 23.33	10.0%
1,500	$ 340.97	$ 374.94	$ 33.97	10.0%
2,000	$ 447.97	$ 492.58	$ 44.61	10.0%
3,000	$ 661.99	$ 727.87	$ 65.89	10.0%
5,000	$ 1,090.01	$ 1,198.46	$ 108.45	9.9%
10,000	$ 2,160.07	$ 2,374.92	$ 214.85	9.9%

Appendix 3 - Recommended Decision
Schedule E Sheet 3 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Comparison of Present and Proposed Electric Bills

S.C. No. 2 - Non Demand

	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	400	430	450	480	500	530	550	580	600
Present Bill	$ 104.91	$ 110.49	$ 114.20	$ 119.78	$ 123.50	$ 129.07	$ 132.79	$ 138.36	$ 142.08
Proposed Bill	$ 117.60	$ 123.97	$ 128.22	$ 134.60	$ 138.85	$ 145.23	$ 149.48	$ 155.86	$ 160.11
$ Increase	$ 12.69	$ 13.49	$ 14.02	$ 14.82	$ 15.36	$ 16.16	$ 16.69	$ 17.49	$ 18.03
% Increase	12.09%	12.21%	12.28%	12.38%	12.44%	12.52%	12.57%	12.64%	12.69%

Appendix 3 - Recommended Decision
Schedule E Sheet 4 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Comparison of Present and Proposed Electric Bills

S.C. No. 2 - Secondary Demand

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 246.86	$ 271.54	$ 296.21	$ 394.92	$ 444.27					
Proposed Bill	$ 277.53	$ 302.18	$ 326.84	$ 425.45	$ 474.76					
Delivery Rate Increase	$ 30.67	$ 30.65	$ 30.62	$ 30.53	$ 30.49					
Total $ Increase	$ 30.67	$ 30.65	$ 30.62	$ 30.53	$ 30.49					
Total % Increase	12.42%	11.29%	10.34%	7.73%	6.86%					
10										
Present Bill	$ 324.12	$ 348.80	$ 373.47	$ 472.18	$ 521.53					
Proposed Bill	$ 365.46	$ 390.12	$ 414.77	$ 513.38	$ 562.69					
Delivery Rate Increase	$ 41.34	$ 41.32	$ 41.30	$ 41.21	$ 41.16					
$ Increase	$ 41.34	$ 41.32	$ 41.30	$ 41.21	$ 41.16					
% Increase	12.75%	11.85%	11.06%	8.73%	7.89%					
15										
Present Bill			$ 450.74	$ 549.44	$ 598.79	$ 845.55	$ 1,092.30			
Proposed Bill			$ 502.70	$ 601.32	$ 650.62	$ 897.15	$ 1,143.69			
Delivery Rate Increase			$ 51.97	$ 51.88	$ 51.83	$ 51.61	$ 51.38			
$ Increase			$ 51.97	$ 51.88	$ 51.83	$ 51.61	$ 51.38			
% Increase			11.53%	9.44%	8.66%	6.10%	4.70%			
20										
Present Bill				$ 626.70	$ 676.05	$ 922.81	$ 1,169.56	$ 1,416.32		
Proposed Bill				$ 689.25	$ 738.55	$ 985.09	$ 1,231.62	$ 1,478.15		
Delivery Rate Increase				$ 62.55	$ 62.51	$ 62.28	$ 62.05	$ 61.83		
$ Increase				$ 62.55	$ 62.51	$ 62.28	$ 62.05	$ 61.83		
% Increase				9.98%	9.25%	6.75%	5.31%	4.37%		
30										
Present Bill					$ 830.57	$ 1,077.33	$ 1,324.09	$ 1,570.84	$ 2,064.36	
Proposed Bill					$ 914.42	$ 1,160.95	$ 1,407.48	$ 1,654.02	$ 2,147.08	
Delivery Rate Increase					$ 83.85	$ 83.62	$ 83.40	$ 83.17	$ 82.72	
$ Increase					$ 83.85	$ 83.62	$ 83.40	$ 83.17	$ 82.72	
% Increase					10.10%	7.76%	6.30%	5.29%	4.01%	
40										
Present Bill						$ 1,231.85	$ 1,478.61	$ 1,725.36	$ 2,218.88	$ 2,712.39
Proposed Bill						$ 1,336.82	$ 1,583.35	$ 1,829.88	$ 2,322.94	$ 2,816.01
Delivery Rate Increase						$ 104.97	$ 104.74	$ 104.52	$ 104.07	$ 103.62
$ Increase						$ 104.97	$ 104.74	$ 104.52	$ 104.07	$ 103.62
% Increase						8.52%	7.08%	6.06%	4.69%	3.82%
50										
Present Bill						$ 1,386.37	$ 1,633.13	$ 1,879.89	$ 2,373.40	$ 2,866.91
Proposed Bill						$ 1,512.68	$ 1,759.22	$ 2,005.75	$ 2,498.81	$ 2,991.87
Delivery Rate Increase						$ 126.31	$ 126.09	$ 125.86	$ 125.41	$ 124.96
$ Increase						$ 126.31	$ 126.09	$ 125.86	$ 125.41	$ 124.96
% Increase						9.11%	7.72%	6.70%	5.28%	4.36%
100										
Present Bill						$ 2,158.98	$ 2,405.74	$ 2,652.49	$ 3,146.01	$ 3,639.52
Proposed Bill						$ 2,392.01	$ 2,638.54	$ 2,885.08	$ 3,378.14	$ 3,871.20
Delivery Rate Increase						$ 233.03	$ 232.81	$ 232.58	$ 232.13	$ 231.68
$ Increase						$ 233.03	$ 232.81	$ 232.58	$ 232.13	$ 231.68
% Increase						10.79%	9.68%	8.77%	7.38%	6.37%

Appendix 3 - Recommended Decision
Schedule E Sheet 5 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Comparison of Present and Proposed Electric Bills

S.C. No. 2 - Primary Demand

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 596.43	$ 620.69	$ 644.96	$ 742.04	$ 790.57					
Proposed Bill	$ 641.52	$ 665.78	$ 690.05	$ 787.11	$ 835.64					
Delivery Rate Increase	$ 45.09	$ 45.09	$ 45.08	$ 45.07	$ 45.07					
Total $ Increase	$ 45.09	$ 45.09	$ 45.08	$ 45.07	$ 45.07					
Total % Increase	7.56%	7.26%	6.99%	6.07%	5.70%					
10										
Present Bill	$ 653.29	$ 677.56	$ 701.83	$ 798.91	$ 847.44					
Proposed Bill	$ 703.39	$ 727.66	$ 751.93	$ 848.99	$ 897.52					
Delivery Rate Increase	$ 50.10	$ 50.10	$ 50.09	$ 50.08	$ 50.08					
Total $ Increase	$ 50.10	$ 50.10	$ 50.09	$ 50.08	$ 50.08					
Total % Increase	7.67%	7.39%	7.14%	6.27%	5.91%					
15										
Present Bill			$ 758.70	$ 855.77	$ 904.31	$ 1,146.99	$ 1,389.68			
Proposed Bill			$ 813.80	$ 910.87	$ 959.40	$ 1,202.06	$ 1,444.72			
Delivery Rate Increase			$ 55.10	$ 55.09	$ 55.09	$ 55.06	$ 55.04			
Total $ Increase			$ 55.10	$ 55.09	$ 55.09	$ 55.06	$ 55.04			
Total % Increase			7.26%	6.44%	6.09%	4.80%	3.96%			
20										
Present Bill				$ 912.64	$ 961.18	$ 1,203.86	$ 1,446.55	$ 1,689.23		
Proposed Bill				$ 972.75	$ 1,021.28	$ 1,263.94	$ 1,506.60	$ 1,749.26		
Delivery Rate Increase				$ 60.11	$ 60.10	$ 60.07	$ 60.05	$ 60.02		
Total $ Increase				$ 60.11	$ 60.10	$ 60.07	$ 60.05	$ 60.02		
Total % Increase				6.59%	6.25%	4.99%	4.15%	3.55%		
30										
Present Bill					$ 1,074.91	$ 1,317.60	$ 1,560.28	$ 1,802.97	$ 2,288.33	
Proposed Bill					$ 1,145.04	$ 1,387.69	$ 1,630.35	$ 1,873.01	$ 2,358.33	
Delivery Rate Increase					$ 70.12	$ 70.10	$ 70.07	$ 70.05	$ 70.00	
Total $ Increase					$ 70.12	$ 70.10	$ 70.07	$ 70.05	$ 70.00	
Total % Increase					6.52%	5.32%	4.49%	3.89%	3.06%	
40										
Present Bill						$ 1,431.34	$ 1,674.02	$ 1,916.70	$ 2,402.07	$ 2,887.44
Proposed Bill						$ 1,511.45	$ 1,754.11	$ 1,996.77	$ 2,482.09	$ 2,967.41
Delivery Rate Increase						$ 80.12	$ 80.09	$ 80.07	$ 80.02	$ 79.97
Total $ Increase						$ 80.12	$ 80.09	$ 80.07	$ 80.02	$ 79.97
Total % Increase						5.60%	4.78%	4.18%	3.33%	2.77%
50										
Present Bill						$ 1,545.07	$ 1,787.76	$ 2,030.44	$ 2,515.81	$ 3,001.18
Proposed Bill						$ 1,635.21	$ 1,877.87	$ 2,120.53	$ 2,605.85	$ 3,091.16
Delivery Rate Increase						$ 90.14	$ 90.11	$ 90.09	$ 90.04	$ 89.99
Total $ Increase						$ 90.14	$ 90.11	$ 90.09	$ 90.04	$ 89.99
Total % Increase						5.83%	5.04%	4.44%	3.58%	3.00%
100										
Present Bill						$ 2,113.75	$ 2,356.44	$ 2,599.12	$ 3,084.49	$ 3,569.86
Proposed Bill						$ 2,254.00	$ 2,496.66	$ 2,739.31	$ 3,224.63	$ 3,709.95
Delivery Rate Increase						$ 140.24	$ 140.22	$ 140.19	$ 140.14	$ 140.09
Total $ Increase						$ 140.24	$ 140.22	$ 140.19	$ 140.14	$ 140.09
Total % Increase						6.63%	5.95%	5.39%	4.54%	3.92%

Appendix 3 - Recommended Decision
Schedule E Sheet 6 of 6
Central Hudson Gas & Electric Corporation

Comparison of Present and Proposed Electric Rates
Cases 23-E-0418 & 23-G-0419
Rates Utilized in Development of Typical Bills
Rates in effect May 1, 2024

					per kW	
	SC 1	SC 2 ND	SC 2 SD	SC 2 PD	SC 2 SD	SC 2 PD
Market Price Charge	$ 0.08579	$ 0.08579	$ 0.08579	$0.08531		
Market Price Adjustment	$ (0.00222)	$ (0.00222)	$ (0.00222)	$0.00037		
Purchased Power Adjustment	$ -	$ -	$ -	$ -		
Miscellaneous Charges*	$ 0.00103	$ 0.00103	$ 0.00103	$ 0.00103	$0.16	$0.07
System Benefits Charge**	$ 0.00866	$ 0.00866	$ 0.00866	$ 0.00866		
MFC Admin Charge****	$ 0.00142	$ 0.00209	$ 0.00010	$ 0.00001		
MFC Supply Charge****	$ 0.00337	$ 0.00541	$ 0.00039	$ 0.00005		
MFC Transition Adjustment****	$ 0.00010	$ 0.00050	$ 0.00008	$ 0.00001		
EAM/RAM	$ 0.00512	$ 0.00480	$ -	$ -	$2.55	$1.49
Electric Bill Credit****	$ -	$ -	$ -	$ -		
DLM	$ 0.00001	$ 0.00001	$ -	$ -		
VDER CR	$ 0.00218	$ 0.00707				
	$ 0.00447	$ 0.00587	$ 0.02184	$ 0.27171		
Weighted Revenue Tax - Commodity	0.208%	0.208%	0.208%	0.208%		
Weighted Revenue Tax - Delivery	2.258%	0.208%	0.208%	0.208%		
MFC Admin Charge - Proposed	$ 0.00092	$ 0.00134	$ 0.00007	$ 0.00001		
MFC Supply Charge - Proposed***	$ 0.00231	$ 0.00386	$ 0.00033	$ 0.00004		
Electric Bill Credit - Proposed	$ -	$ -	$ -	$ -		

*Includes MISC II.

**In order to only show the impact of base rate increases, bills under proposed rates do not reflect changes to the DLM VDER CR, SBC, EAM and RAM. These items have been included at current rates but are subject to change.

***The MFC Supply Charge includes 50 percent of forecast net lost revenues associated with customer migration and therefore is subject to change each year based on the calculation of actual net lost revenues. Current allocation of MFC Lost Revenue Charge included in Proposed MFC Supply.

Market Price Charge, Market Price Adjustment, and Miscellaneous Charges are included using a 12 month average of June 2023 - May 2024

Appendix 3 - Recommended Decision
Schedule F Sheet 1 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Average Annual Residential Gas Heating Customer Bill Impact
Twelve Months Ended June 30, 2025

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Block 1 Ccf	24	24	24	24	
Block 2 Ccf	406	406	387	387	
Block 3 Ccf	349	349	260	260	
Total Annual Ccf	**780**	**780**	**750**	**750**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 24.25	$26.25	$ 24.25	$ 26.25	
Gas Delivery Charges $/Ccf					
Next	$1.36250	$1.51410	$1.36250	$1.51410	
Next	$0.94790	$1.28350	$0.94790	$1.28350	
System Benefits Charge	$0.00000	$0.00000	$0.00000	$0.00000	
MFC Admin Charge	$0.00533	$0.00484	$0.00533	$0.00484	
Transition Adj Charge	$0.00372	$0.00372	$0.00372	$0.00372	
Miscellaneous	$0.03021	$0.03021	$0.03021	$0.03021	
Gas Bill Credit	$0.00000	$0.00000	$0.00000	$0.00000	
Gas Supply Charges $Ccf					
MFC Supply Charge	$0.01208	$0.01313	$0.01208	$0.01313	
Gas Supply Charge	$0.44852	$0.44852	$0.44852	$0.44852	
Rev Tax Factor					
Weighted Rev Tax - Commodity	0.00522	0.00522	0.00522	0.00522	
Weighted Rev Tax - Delivery	0.02522	0.02522	0.02522	0.02522	
CHG&E Bill			LOW INCOME		
Gas Delivery Charges:					
Basic Service Charge	$298.53	$323.15	$298.53	$323.15	
Next	$567.49	$630.63	$540.93	$601.12	
Next	$339.38	$459.53	$252.83	$342.34	
System Benefits Charge	$0.00	$0.00	$0.00	$0.00	
MFC Admin Charge	$4.26	$3.87	$4.10	$3.72	
Transition Adj Charge	$2.98	$2.98	$2.86	$2.86	
Miscellaneous	$24.17	$24.17	$23.24	$23.24	
Gas Bill Credit	$0.00	$0.00	$0.00	$0.00	
Subtotal Delivery	$1,236.81	$1,444.33	$1,122.50	$1,296.44	
Gas Supply Charges:					
MFC Supply Charge	$9.67	$10.51	$9.29	$10.10	
Gas Supply Charge	$351.68	$351.68	$338.16	$338.16	
Subtotal Energy Supply	$361.35	$362.19	$347.45	$348.26	
Low Income Bill Discount	$0.00	$0.00	($275.88)	($344.88)	(Tier 1 Discount)
Total Bill	**$1,598.15**	**$1,806.52**	**$1,194.07**	**$1,299.82**	
$ Total Bill Increase		$208.37		$105.75	
% Total Bill Increase		13.04%		8.86%	

Appendix 3 - Recommended Decision
Schedule F Sheet 2 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Gas Residential Typical Monthly Bill
Twelve Months Ended June 30, 2025

Delivery Only				
Monthly Ccf	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
2	$ 24.92	$ 26.97	$ 2.05	8.24%
4	$ 27.76	$ 30.12	$ 2.37	8.52%
6	$ 30.60	$ 33.28	$ 2.68	8.75%
8	$ 33.44	$ 36.43	$ 2.99	8.94%
10	$ 36.28	$ 39.58	$ 3.30	9.10%
15	$ 43.37	$ 47.46	$ 4.08	9.41%
20	$ 50.47	$ 55.33	$ 4.86	9.63%
25	$ 57.57	$ 63.21	$ 5.64	9.80%
30	$ 64.66	$ 71.09	$ 6.42	9.93%
35	$ 71.76	$ 78.97	$ 7.20	10.04%
40	$ 78.86	$ 86.84	$ 7.98	10.13%
50	$ 93.05	$ 102.60	$ 9.55	10.26%
60	$ 102.99	$ 115.99	$ 12.99	12.62%
80	$ 122.88	$ 142.77	$ 19.89	16.19%
100	$ 142.76	$ 169.55	$ 26.79	18.76%
130	$ 172.58	$ 209.72	$ 37.13	21.52%
170	$ 212.35	$ 263.27	$ 50.93	23.98%
200	$ 242.17	$ 303.44	$ 61.27	25.30%
300	$ 341.58	$ 437.34	$ 95.76	28.03%
1,000	$ 1,037.45	$ 1,374.61	$ 337.16	32.50%

Total Bill				
Monthly Ccf	Bill at Current Rates	Bill at Proposed RY 1 Rates	Over Current Amount	Over Current %
2	$ 25.88	$ 27.94	$ 2.05	7.93%
4	$ 29.69	$ 32.05	$ 2.37	7.97%
6	$ 33.49	$ 36.17	$ 2.68	7.99%
8	$ 37.29	$ 40.28	$ 2.99	8.02%
10	$ 41.09	$ 44.40	$ 3.30	8.03%
15	$ 50.60	$ 54.68	$ 4.08	8.07%
20	$ 60.11	$ 64.97	$ 4.86	8.09%
25	$ 69.61	$ 75.26	$ 5.64	8.11%
30	$ 79.12	$ 85.54	$ 6.42	8.12%
35	$ 88.63	$ 95.83	$ 7.20	8.13%
40	$ 98.13	$ 106.12	$ 7.98	8.14%
50	$ 117.15	$ 126.69	$ 9.55	8.15%
60	$ 131.91	$ 144.90	$ 12.99	9.85%
80	$ 161.43	$ 181.32	$ 19.89	12.32%
100	$ 190.94	$ 217.73	$ 26.79	14.03%
130	$ 235.22	$ 272.36	$ 37.13	15.79%
170	$ 294.26	$ 345.19	$ 50.93	17.31%
200	$ 338.54	$ 399.82	$ 61.27	18.10%
300	$ 486.14	$ 581.90	$ 95.76	19.70%
1,000	$ 1,519.31	$ 1,856.47	$ 337.16	22.19%

Appendix 3 - Recommended Decision
Schedule F Sheet 3 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Gas Commercial Typical Monthly Bill
Twelve Months Ended June 30, 2025

Delivery Only				
Monthly Ccf	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
2	$ 39.28	$ 41.29	$ 2.01	5.12%
10	$ 44.09	$ 47.30	$ 3.21	7.29%
30	$ 56.12	$ 62.33	$ 6.21	11.07%
50	$ 68.14	$ 77.36	$ 9.21	13.52%
100	$ 98.20	$ 114.92	$ 16.72	17.02%
150	$ 127.32	$ 151.89	$ 24.57	19.30%
200	$ 156.43	$ 188.85	$ 32.42	20.72%
250	$ 185.55	$ 225.82	$ 40.27	21.70%
300	$ 214.66	$ 262.78	$ 48.12	22.42%
400	$ 272.89	$ 336.71	$ 63.82	23.39%
500	$ 331.12	$ 410.64	$ 79.53	24.02%
600	$ 389.34	$ 484.57	$ 95.23	24.46%
800	$ 505.80	$ 632.43	$ 126.63	25.04%
1,000	$ 622.26	$ 780.29	$ 158.04	25.40%
1,500	$ 913.40	$ 1,149.95	$ 236.55	25.90%
2,000	$ 1,204.54	$ 1,519.60	$ 315.06	26.16%
3,000	$ 1,786.82	$ 2,258.90	$ 472.09	26.42%
5,000	$ 2,951.37	$ 3,737.51	$ 786.14	26.64%
7,500	$ 4,252.52	$ 5,486.38	$ 1,233.87	29.02%
10,000	$ 5,553.66	$ 7,235.26	$ 1,681.60	30.28%
12,000	$ 6,594.57	$ 8,634.36	$ 2,039.79	30.93%
14,000	$ 7,635.49	$ 10,033.46	$ 2,397.97	31.41%
16,000	$ 8,676.40	$ 11,432.56	$ 2,756.16	31.77%
20,000	$ 10,758.23	$ 14,230.75	$ 3,472.53	32.28%

Total Bill				
Monthly Ccf	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
2	$ 40.20	$ 42.21	$ 2.01	5.01%
10	$ 48.68	$ 51.90	$ 3.21	6.60%
30	$ 69.90	$ 76.11	$ 6.21	8.89%
50	$ 91.12	$ 100.33	$ 9.21	10.11%
100	$ 144.16	$ 160.87	$ 16.72	11.60%
150	$ 196.25	$ 220.81	$ 24.57	12.52%
200	$ 248.33	$ 280.75	$ 32.42	13.05%
250	$ 300.42	$ 340.69	$ 40.27	13.40%
300	$ 352.51	$ 400.63	$ 48.12	13.65%
400	$ 456.69	$ 520.52	$ 63.82	13.98%
500	$ 560.87	$ 640.40	$ 79.53	14.18%
600	$ 665.05	$ 760.28	$ 95.23	14.32%
800	$ 873.41	$ 1,000.04	$ 126.63	14.50%
1,000	$ 1,081.77	$ 1,239.80	$ 158.04	14.61%
1,500	$ 1,602.66	$ 1,839.21	$ 236.55	14.76%
2,000	$ 2,123.55	$ 2,438.62	$ 315.06	14.84%
3,000	$ 3,165.34	$ 3,637.43	$ 472.09	14.91%
5,000	$ 5,248.92	$ 6,035.05	$ 786.14	14.98%
7,500	$ 7,698.83	$ 8,932.70	$ 1,233.87	16.03%
10,000	$ 10,148.74	$ 11,830.34	$ 1,681.60	16.57%
12,000	$ 12,108.68	$ 14,148.46	$ 2,039.79	16.85%
14,000	$ 14,068.61	$ 16,466.58	$ 2,397.97	17.04%
16,000	$ 16,028.54	$ 18,784.69	$ 2,756.16	17.20%
20,000	$ 19,948.40	$ 23,420.93	$ 3,472.53	17.41%

Appendix 3 - Recommended Decision
Schedule G Sheet 1 of 2
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Illustrative Example of Make Whole Provision - Electric

	Jul-24			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	260,373	174,200,300		$ 19.50	$ 0.10546	$ 0.00468	$ -		$ 21.50	$ 0.12782	$ 0.00312	$ -		$ 4,144,113
SC 2 Non Demand	32,898	15,762,037		$ 30.50	$ 0.07234	$ 0.00687	$ -		$ 32.50	$ 0.10129	$ 0.00457	$ -		$ 485,854
SC 2 Secondary	11,355	125,344,322	379,831	$ 120.00	$ 0.00467	$ 0.00032	$ -	$ 12.71	$ 140.00	$ 0.00467	$ 0.00023	$ -	$ 14.84	$ 1,024,859
SC 2 Primary	150	19,465,000	55,614	$ 490.00	$ 0.00144	$ 0.00003	$ -	$ 9.79	$ 530.00	$ 0.00144	$ 0.00002	$ -	$ 10.79	$ 61,431
SC 3 Primary	32	26,752,000	60,800	$ 2,400.00			$ -	$ 12.56	$ 2,600.00		$ -	$ -	$ 13.64	$ 72,064
SC 5 Area Lighting **	3,731	810,000		$ 216,300.00		$ 0.01352	$ -		$ 269,640.00		$ 0.00811	$ -		$ 53,340
SC 6 Residential TOU 12 Hour on pk^^	1,130	484,000		$ 22.50	$ 0.13826	$ 0.00215	$ -		$ 24.50	$ 0.16303	$ 0.00235	$ -		$ 14,345
SC 6 Residential TOU 12 Hour off pk^^		396,000			$ 0.04612	$ 0.00215	$ -			$ 0.05434	$ 0.00235	$ -		$ 3,334
SC 6 Residential TOU 5 Hour on pk				$ 22.50	$ 0.10987	$ 0.00215	$ -		$ 24.50	$ 0.13513	$ 0.00235	$ -		
SC 6 Residential TOU 5 Hour off pk					$ 0.09501	$ 0.00215	$ -			$ 0.11685	$ 0.00235	$ -		
SC 8 Street Lighting **	209	700,000		$ 414,487.00		$ 0.00066	$ -		$475,563		$ 0.00054	$ -		$ 61,076
SC 9 Traffic Signals	59	60,000		$ 4.26		$ 0.01050	$ -		$ 4.98		$ 0.00224	$ -		$ (453)
SC 13 Substation	6	10,024,900	16,828	$ 7,500.00			$ -	$ 10.11	$ 8,500.00		$ -	$ -	$ 11.03	$ 21,482
SC 13 Transmission	6	57,917,303	93,462	$ 12,000.00			$ -	$ 5.95	$ 13,500.00		$ -	$ -	$ 6.62	$ 71,620
Total														**$ 6,013,066**

^^ 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.

Appendix 3 - Recommended Decision
Schedule G Sheet 2 of 2
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Illustrative Example of Make Whole Provision - Gas

	Jul-24			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	75,622	13,815		$ 24.25			$ -		$ 26.25			$ -		$ 151,244
Block 2		100,567			$ 1.36250					$ 1.5141				$ 152,460
Block 3		7,459			$ 0.94790					$ 1.2835				$ 25,032
MFC						$ 0.01741					$ 0.01797			$ 682
Gas Bill Credit														$ -
SC 2/6/13 Non-Residential														
Block 1	12,794	1,606		$ 39.00			$ -		$ 41.00			$ -		$ 25,588
Block 2		36,497			$ 0.56090					$ 0.7090				$ 54,052
Block 3		103,157			$ 0.54200					$ 0.6971				$ 159,950
Block 4		33,629			$ 0.48050					$ 0.6575				$ 59,525
SC 6 High Volume		47,668			$ 0.38690					$ 0.5945				$ 98,955
MFC						$ 0.01676					$ 0.01791			$ 2,011
Gas Bill Credit														$ -
SC 11 DLM														
Customer Charge - First 1,000 ccf	1			$ 7,600.00			$ -		$ 7,100.00			$ -		
Block 1		100			$ 0.02750					$ 0.0347				$ (500)
Block 2		28,655												$ 2,056
MDQ			4,900					$ 15.48					$ 18.36	$ 14,112
Gas Bill Credit														$ -
SC 11 D														
Customer Charge - First 1,000 ccf	4			$ 2,100.00			$ -		$ 2,400.00			$ -		
Block 1		320			$ 0.04040					$ 0.0500				$ 1,200
Block 2		18,630												$ 1,800
MDQ			4,752					$ 21.35					$ 26.50	$ 24,473
Gas Bill Credit														$ -
SC 11 T														
Customer Charge - First 1,000 ccf	2			$ 4,800.00			$ -		$ 4,000.00			$ -		
Block 1		200			$ 0.01890					$ 0.0231				$ (1,600)
Block 2		40,060												$ 1,683
MDQ			8,548					$ 9.23					$ 11.22	$ 17,011
Gas Bill Credit														$ -
SC 11 EG														
Customer Charge	2			$ 2,000.00					$ 3,000.00					$ 2,000
MDQ			10,000					$ 15.16					$ 18.37	$ 32,100
Total														**$ 823,833**

Appendix 4 - Updates & Corrections
Schedule A Sheet 1 of 2
Cases 23-E-0418 & 23-G-0419
Central Hudson Gas & Electric Corporation
Electric Revenue Allocation

Twelve Months Ending June 30, 2025

	Min .75x, Max 1.25x	Rate Increase	Hydro Revenues	Total Rate increase
Incremental Revenue Requirement Excluding Taxes	(1)	$ 73,488,000	**$ 4,400,000**	**$ 77,888,000**
Percentage On Base Rates	(2)	**17.25%**		

	(3) Unitized Rate of Return Historic	(4) Unitized Rate of Return Information Only	(5) Unitized Rate of Return Pro Forma	(6) Revenue Allocation Factor	(7) RY Sales at Current Rates	(8)=(2)x(6)x(7) Base Rev Increase	(9) Adjustment **$ (713,125)**	(10)=(8)+(9) Total	(11) Revenue % Increase	(12) MFC Revenue from Current Base Rates	(13) Total Estimated MFC Revenue	(14)=(12)-(13) MFC Adjustment to Rate Increase	(15)=(10)+(14) Adj Base Rev Increase	(16) Hydro Revenues	(17) Adjusted Delivery Revenues	(18) Adj Increase as % of System	(19) Delivery Increase Percent
SC 1 Residential	0.88	0.88	1.08	**1.00**	$ 312,699,441	$ 53,942,623	$ (489,406)	$ 53,453,217	17.09%	$ 10,694,321	$ 6,695,390	$ 3,998,931	$ 57,452,149	$ (1,979,151)	$ 55,472,998	70.90%	18.37%
SC 2 Non Demand	0.63	0.79	0.53	**1.25**	$ 28,177,405	$ 6,075,975	$ (55,126)	$ 6,020,849	21.37%	$ 1,378,034	$ 860,523	$ 517,510	$ 6,538,360	$ (168,466)	$ 6,369,893	8.14%	23.77%
SC 2 Secondary	1.16	1.03	0.69	**1.00**	$ 76,380,468	$ 13,176,112	$ (119,543)	$ 13,056,569	17.09%	$ 432,628	$ 283,917	$ 148,711	$ 13,205,280	$ (1,181,125)	$ 12,024,155	15.37%	15.83%
SC 2 Primary	3.63	2.78	1.86	**0.75**	$ 6,809,674	$ 881,034	$ (7,993)	$ 873,040	12.82%	$ 6,720	$ 4,497	$ 2,223	$ 875,264	$ (187,493)	$ 687,771	0.88%	10.11%
SC 3 Primary	2.63	2.45	2.73	**0.75**	$ 9,052,558	$ 1,171,217	$ (10,626)	$ 1,160,591	12.82%	$ -	$ -	$ -	$ 1,160,591	$ (242,614)	$ 917,978	1.17%	10.14%
SC 5 Area Lighting	(0.48)	0.74	(0.03)	**1.25**	$ 2,756,300	$ 594,349	$ (5,392)	$ 588,957	21.37%	$ 168,680	$ 95,021	$ 73,659	$ 662,615	$ (10,617)	$ 651,998	0.83%	25.20%
SC 6 Residential TOU	1.63	1.91	1.10	**1.00**	$ 1,512,830	$ 260,973	$ (2,368)	$ 258,605	17.09%	$ 28,450	$ 29,216	$ (766)	$ 257,839	$ (11,508)	$ 246,331	0.31%	16.59%
SC 8 Street Lighting	3.94	3.31	2.44	**0.75**	$ 5,036,243	$ 651,588	$ (5,912)	$ 645,676	12.82%	$ 7,020	$ 5,325	$ 1,695	$ 647,371	$ (9,067)	$ 638,304	0.82%	12.69%
SC 9 Traffic Signals	1.21	(1.63)	19.50	**0.75**	$ 187,930	$ 24,314	$ (221)	$ 24,094	12.82%	$ 7,560	$ 1,512	$ 6,048	$ 30,142	$ (613)	$ 29,529	0.04%	16.37%
SC 13 Substation	2.56	2.43	0.96	**1.00**	$ 2,206,970	$ 380,716	$ (3,454)	$ 377,262	17.09%	$ -	$ -	$ -	$ 377,262	$ (91,559)	$ 285,703	0.37%	12.95%
SC 13 Transmission	0.50	1.85	0.18	**1.25**	$ 6,688,334	$ 1,442,225	$ (13,085)	$ 1,429,140	21.37%	$ -	$ -	$ -	$ 1,429,140	$ (517,787)	$ 911,353	1.16%	13.63%
Total	1.00	1.00	1.00		$ 451,508,153	$ 78,601,125	$ (713,125)	$ 77,888,000	17.25%	$ 12,723,413	$ 7,975,401	$ 4,748,011	$ 82,636,011	$ (4,400,000)	$ 78,236,011	100%	17.83%

Appendix 4 - Updates & Corrections
Schedule A Sheet 2 of 2
Central Hudson Gas & Electric Corporation
Electric Energy Efficiency Base Rate Design
Cases 23-E-0418 & 23-G-0419
Twelve Months Ending June 30, 2025

	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	832,607		68.27%	8.67%	2,285,116		48.58%	42.41%	51.08%
SC 2 Non Demand	23,813		1.95%	0.25%	200,588		4.27%	3.72%	3.97%
SC 2 Secondary	276,044	1,746	22.49%	2.86%	1,351,986	8,903	28.56%	24.93%	27.78%
SC 2 Primary	27,676	716	2.21%	0.28%	224,829	3,526	4.71%	4.11%	4.39%
SC 3 Primary	34,374	1,212	2.72%	0.35%	283,101	6,381	5.88%	5.14%	5.48%
SC 5 Area Lighting	-		0.00%	0.00%	12,470		0.27%	0.23%	0.23%
SC 6 Residential TOU	2,728		0.22%	0.03%	13,220		0.28%	0.25%	0.27%
SC 8 Street Lighting	-		0.00%	0.00%	10,650		0.23%	0.20%	0.20%
SC 9 Traffic Signals	13		0.00%	0.00%	720		0.02%	0.01%	0.01%
SC 13 Substation	11,252	5,980	0.43%	0.05%	110,127	45,200	1.38%	1.20%	1.26%
SC 13 Transmission	67,240	46,510	1.70%	0.22%	627,338	352,583	5.84%	5.10%	5.32%
Total	1,275,747	56,164	100.00%	12.70%	5,120,145	416,592	100.00%	87.30%	100.00%

	Total Allocator	$ 5,630,000 **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 RY3**	**RY3 Base Rate**
SC 1 Residential	51.08%	$ 2,875,987										$ 2,875,987	$ 2,875,987	$ 1,135,400	$ 4,583,858
SC 2 Non Demand	3.97%	$ 223,588										$ 223,588	$ 223,588	$ 182,968	$ 360,880
SC 2 Secondary	27.78%	$ 1,564,288	4,184,672	20,952	4,163,720	$ 7,832	$ 0.002	$ 0.374	$ 0.376	$ 1,573,437	$ (7,878)	$ 1,565,559	$ 1,573,437	$ (790,841)	$ 3,054,633
SC 2 Primary	4.39%	$ 247,059	562,613	8,592	554,021	$ 3,773	$ 0.007	$ 0.439	$ 0.446	$ 250,925	$ (3,832)	$ 247,093	$ 250,925	$ (104,087)	$ 397,619
SC 3 Primary	5.48%	$ 308,590	641,624	14,544	627,080	$ 6,995	$ 0.011	$ 0.481	$ 0.492	$ 315,679	$ (7,156)	$ 308,523	$ 315,679	$ (214,040)	$ 586,933
SC 5 Area Lighting	0.23%	$ 13,025										$ 13,025	$ 13,025	$ 23,962	$ 20,391
SC 6 Residential TOU	0.27%	$ 15,413										$ 15,413	$ 15,413	$ (4,073)	$ 33,242
SC 8 Street Lighting	0.20%	$ 11,108										$ 11,108	$ 11,108	$ 23,441	$ 22,012
SC 9 Traffic Signals	0.01%	$ 744										$ 744	$ 744	$ 411	$ 1,615
SC 13 Substation	1.26%	$ 70,916	181,882	71,760	110,122	$ 27,979	$ 0.254	$ 0.390	$ 0.644	$ 117,132	$ (46,213)	$ 70,919	$ 117,132	$ (79,775)	$ 210,185
SC 13 Transmission	5.32%	$ 299,240	1,045,131	558,120	487,011	$ 159,800	$ 0.328	$ 0.286	$ 0.614	$ 641,710	$ (342,686)	$ 299,024	$ 641,710	$ (174,729)	$ 831,291
Total	100.00%	$ 5,629,958									$ (407,765)	$ 5,630,983	$ 6,038,748	$ (1,365)	$ 10,102,659

Appendix 4 - Updates & Corrections
Schedule B
Central Hudson Gas & Electric Corporation
Cases 23-E 0418 & 23-G-0419
Gas Revenue Allocation - Twelve Months Ending June 30, 2025

			Danskammer Imputation	$ 1,000,000
Base Rate Increase		$ 26,475,000		$ -
Incremental Revenue Requirement	(1)	**$ 26,475,000**	**Interruptible Imputation**	$ 3,200,000
Percentage On Base Rates	(2)	**19.48%**		$ -

	(3) Unitized Rate of Return Historic	(4)	(5) Unitized Rate of Return Pro Forma	(6) Revenue Allocation Factor	(7) RY Block Revs at Current Rates (Incl MFC)	(8)=(2)x(6)x(7) Base Rev Increase	(9) Adjustment **$ 2,109,744**	(10) Interruptible Imputation	(11) Danskammer Imputation	(12)=(8)+(9)+(10)+(11) Total
SC 1 & 12	1.16		1.17	0.75	$ 85,951,980	$ 12,559,875	$ 1,087,537.31	$ 2,038,131.56	$ 636,916.11	$ 16,322,460
SC 2, 6 & 13	0.43		0.81	1.25	$ 45,046,764	$ 10,970,888	$ 949,950	$ 1,068,168.88	$ 333,802.78	$ 13,322,809
SC 11 Transmission	3.68		4.39	0.75	$ 1,224,266	$ 178,898	$ 15,490	$ 29,030.35	$ 9,071.98	$ 232,491
SC 11 Distribution	0.92		-0.25	1.00	$ 1,543,372	$ 300,704	$ 26,037	$ 36,597.13	$ 11,436.60	$ 374,775
SC 11 - DLM	12.21		1.17	0.75	$ 1,183,854	$ 172,993	$ 14,979	$ 28,072.07	$ 8,772.52	$ 224,816
SC 11 - EG (Excl Danskammer)	0.00		0.00	1.00	$ 933,600	$ 181,898	$ 15,750	$ -	$ -	$ 197,649
Total					135,883,836	$ 24,365,256	$ 2,109,744	$ 3,200,000	$ 1,000,000	$ 30,675,000

	(13) Revenue % Increase	(14) MFC Revenue from Current MFC Rates	(15) Total Estimated MFC Revenue	(16)=(14)-(15) MFC Adjustment to Rate Increase	(17)=(12)+(16) Adj Base Rev Increase	(18) Interruptible Revenues	(19) Danskammer Revenues	(20)=(7)+(17)+(18)+(19) Adjusted Delivery Revenues	(21) Adj Increase as % of System	(22) Delivery Increase Percent
SC 1 & 12	18.99%	$ 983,140	$ 963,376	$ 19,765	$ 16,342,225	$ (2,038,131.56)	$ (636,916.11)	$ 99,619,157	53.27%	15.90%
SC 2, 6 & 13	29.58%	$ 1,265,192	$ 1,282,512	$ (17,321)	$ 13,305,489	$ (1,068,168.88)	$ (333,802.78)	$ 56,950,281	43.37%	26.42%
SC 11 Transmission	18.99%	$ -	$ -	$ -	$ 232,491	$ (29,030.35)	$ (9,071.98)	$ 1,418,655	0.76%	15.88%
SC 11 Distribution	24.28%	$ -	$ -	$ -	$ 374,775	$ (36,597.13)	$ (11,436.60)	$ 1,870,114	1.22%	21.17%
SC 11 - DLM	18.99%	$ -	$ -	$ -	$ 224,816	$ (28,072.07)	$ (8,772.52)	$ 1,371,826	0.74%	15.88%
SC 11 - EG (Excl Danskammer)	21.17%	$ -	$ -	$ -	$ 197,649	$ -	$ -	$ 1,131,248.72	0.64%	21.17%
Total		$ 2,248,332	$ 2,245,888	$ 2,444	$ 30,677,444	$ (3,200,000)	$ (1,000,000)	$ 162,361,281	100.00%	22.96%

Energy Efficiency Allocation

	(23) RY Billing Determinants	(24) EE Change in Allocation	(25) = (17)+(24) Adj Base Rev Increase Incl EE	Interruptible Revenues	Adjusted Delivery Revenues	Adj Increase as % of System	Delivery Increase Percent
SC 1 & 12	5,646,985	$ 178,348	$ 16,520,573	$ (2,038,132)	$ 100,434,422	53.85%	16.85%
SC 2, 6 & 13	7,548,630	$ (164,098)	$ 13,141,391	$ (1,068,169)	$ 57,119,986	42.84%	26.80%
SC 11 Transmission	861,148	$ 3,682	$ 236,172	$ (29,030)	$ 1,431,409	0.77%	16.92%
SC 11 Distribution	561,693	$ (3,290)	$ 371,485	$ (36,597)	$ 1,878,260	1.21%	21.70%
SC 11 - DLM	664,566	$ 1,341	$ 226,157	$ (28,072)	$ 1,381,939	0.74%	16.73%
SC 11 - EG (Excl Danskammer)	60,000	$ (15,983)	$ 181,666	$ -	$ 1,115,266	0.59%	19.46%
Total	15,343,022	$ 0	$ 30,677,444	$ (3,200,000)	$ 163,361,281	100.00%	20.22%

* Estimated billing determinants for Energy Efficiency allocation purposes only - reflects most recent 3 year annual average

$ 1,939,000.00	2023 EET Alloc.			
SC 1/12	$ 985,752	**71.4%**	SC 1 & 12	$ 1,384,021
SC 2/6/11/13	$ 395,277	**28.6%**	SC 2, 6 & 13	$ 432,066
	$ 1,381,029		SC 11 Transmissi	$ 49,290
			SC 11 Distributior	$ 32,150
			SC 11 - DLM	$ 38,038
			SC 11 - EG (Excl	$ 3,434
			Total	$ 1,939,000

$ 1,265,000.00	2020 EET Alloc.				Change
SC 1/12	$ 682,000	**61.6%**	SC 1 & 12	$ 779,341	$ 604,680
SC 2/6/11/13	$ 425,000	**38.4%**	SC 2, 6 & 13	$ 372,727	$ 59,340
	$ 1,107,000		SC 11 Transmissi	$ 39,536	$ 9,754
			SC 11 Distributior	$ 27,785	$ 4,366
			SC 11 - DLM	$ 30,826	$ 7,213
			SC 11 - EG (Excl	$ 14,787	$ (11,352)
			Total	$ 1,265,000	

$ (674,000.00)	2023 EET Alloc.				
SC 1/12	$ 985,752	**63.3%**	SC 1 & 12	$ (426,332)	$ 178,348
SC 2/6/11/13	$ 395,277	**33.2%**	SC 2, 6 & 13	$ (223,437)	$ (164,098)
	$ 1,381,029	**0.9%**	SC 11 Transmissi	$ (6,073)	$ 3,682
		1.1%	SC 11 Distributior	$ (7,655)	$ (3,290)
		0.9%	SC 11 - DLM	$ (5,872)	$ 1,341
		0.7%	SC 11 - EG (Excl	$ (4,631)	$ (15,983)
			Total	$ (674,000)	

UNITIZED RATE OF RETURN
Pro Forma

Pro Forma ECOS	4.05%	TOTAL	1.00	
SC 1 & 12	4.73%	SC 1 & 12	1.17	High
SC 2, 6 & 13	3.30%	SC 2, 6 & 13	0.81	Low
SC 11 Transmission	17.80%	SC 11 Transmission	4.39	High
SC 11 Distribution	-1.02%	SC 11 Distribution	(0.25)	Low
SC 11 - DLM	4.73%	SC 11 - DLM	1.17	High

UNITIZED RATE OF RETURN
Embedded

Historic ECOS	5.59%	TOTAL	1.00	
SC 1 & 12	6.48%	SC 1 & 12	1.16	High
SC 2, 6 & 13	2.40%	SC 2, 6 & 13	0.43	Low
SC 11 Transmission	20.59%	SC 11 Transmission	3.68	High
SC 11 Distribution	5.14%	SC 11 Distribution	0.92	
SC 11 - DLM	68.25%	SC 11 - DLM	12.21	High

UNITIZED RATE OF RETURN
Hypothetical

Hypothetical ECOS	4.07%	TOTAL	1.00	
SC 1 & 12	4.37%	SC 1 & 12	1.07	
SC 2, 6 & 13	3.23%	SC 2, 6 & 13	0.79	Low
SC 11 Transmission	7.71%	SC 11 Transmission	1.89	High
SC 11 Distribution	0.21%	SC 11 Distribution	0.05	Low
SC 11 - DLM	3.29%	SC 11 - DLM	0.81	Low

Appendix 4 - Updates & Corrections
Schedule C Sheet 1 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Proposed Monthly Electric Base Delivery Rates
(Excludes S.C. Nos. 5 & 8, Unbilled & Interdepartmental)

		Current Rates	12 Months Ending Jun-25 Rate Year
S.C. No. 1			
	Customer Charge	$ 19.50	$ 21.50
	kWh Delivery	$ 0.10546	$ 0.12749
S.C. No. 2 - Non-Demand			
	Customer Charge	$ 30.50	$ 32.50
	kWh Delivery	$ 0.07234	$ 0.10099
S.C. No. 2 - Secondary			
	Customer Charge	$ 120.00	$ 140.00
	HPP Customer Charge	$ 150.00	$ 170.00
	kWh Delivery	$ 0.00467	$ 0.00467
	kW Delivery	$ 12.71	$ 14.74
	Rkva*	$ 0.83	$ 0.83
S.C. No. 2 - Primary			
	Customer Charge	$ 490.00	$ 530.00
	HPP Customer Charge	$ 520.00	$ 560.00
	kWh Delivery	$ 0.00144	$ 0.00144
	kW Delivery	$ 9.79	$ 10.70
	Rkva*	$ 0.83	$ 0.83
S.C. No. 3			
	Customer Charge	$ 2,400.00	$ 2,600.00
	kWh Delivery	$ -	$ -
	kW Delivery	$ 12.56	$ 13.54
	Rkva	$ 0.83	$ 0.83
S.C. No. 6			
	Customer Charge	$ 22.50	$ 24.50
	kWh Delivery On Pk	$ 0.13836	$ 0.16258
	kWh Delivery Off Pk	$ 0.04612	$ 0.05419
S.C. No. 6 (5 Hour On-Peak)			
	Customer Charge	$ 22.50	$ 24.50
	kWh Delivery On Pk	$ 0.10987	$ 0.13477
	kWh Delivery Off Pk	$ 0.09501	$ 0.11654
S.C. No. 9			
	Signal Faces	$ 4.26	$ 4.97
S.C. No. 13 - Substation			
	Customer Charge	$ 7,500.00	$ 8,500.00
	kWh Delivery	$ -	$ -
	kW Delivery	$ 10.11	$ 10.93
	Rkva	$ 0.83	$ 0.83
S.C. No. 13 - Transmission			
	Customer Charge	$ 12,000.00	$ 13,500.00
	kWh Delivery	$ -	$ -
	kW Delivery	$ 5.95	$ 6.55
	Rkva	$ 0.83	$ 0.83

Energy Efficiency Exemption Credit Rate per kW:		
	S.C. No. 2 - Secondary	$ 0.38
	S.C. No. 2 - Primary	$ 0.45
	S.C. No. 3	$ 0.49
	S.C. No. 13 - Substation	$ 0.64
	S.C. No. 13 - Transmission	$ 0.61

*As applicable

Appendix 4 - Updates & Corrections
Schedule C Sheet 2 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates

Area Lighting

Service Classification No. 5 - P.S.C. No. 15

Lamp and Fixture Charge

Lumens	Type	Annual kWh	Present Monthly Base Rate	Proposed Monthly Base Rate
First Light				
7,000	Mercury	832	$15.32	$19.08
20,000	Mercury	1,820	$21.43	$26.69
60,000	Mercury	4,320	$35.40	$44.08
5,800	Sodium	344	$12.90	$16.06
16,000	Sodium	721	$15.74	$19.60
27,000	Sodium	1,264	$19.60	$24.41
50,000	Sodium	1,984	$23.44	$29.19
140,000	Sodium	4,656	$41.75	$51.99
50,000	Sodium - Floodlight	1,984	$23.99	$29.87
20,500	Metal Halide	1,200	$19.76	$24.61
36,000	Metal Halide	1,856	$22.45	$27.96
36,000	Metal Halide - Floodlight	1,856	$23.18	$28.86
110,000	Metal Halide - Floodlight	4,400	$39.20	$48.81
14,001	Metal Halide (P)	820	$43.66	$54.37
20,501	Metal Halide (P)	1,200	$51.37	$63.97
36,001	Metal Halide	1,856	$61.29	$76.32
5,801	Sodium Vapor (P)	344	$26.55	$33.06
2,900	LED	100	$15.62	$19.45
6,800	LED	260	$16.37	$20.38
9,500	LED	380	$18.74	$23.34
16,500	LED	620	$24.90	$31.01
3,000	LED	120	$11.73	$14.61
2,000	LED	80	$13.11	$16.33
5,250	LED	212	$13.73	$17.10
7,500	LED	300	$15.73	$19.59
13,000	LED	520	$20.89	$26.01
17,750	LED	712	$25.32	$31.53
27,500	LED	1100	$31.29	$38.96
1,500	LED	60	$18.43	$22.95
2,500	LED	100	$27.98	$34.84
8,000	LED	320	$22.58	$28.12
15,250	LED	612	$31.56	$39.30
25,750	LED	1032	$38.65	$48.13
12,000	LED	480	$63.19	$78.69
16,001	LED	640	$52.84	$65.80

Lamp, Fixture and Pole Package Charge

Lumens	Type	Annual kWhrs	Present Monthly Base Rate	Proposed Monthly Base Rate
14,000	Metal Halide	820	$43.66	$54.37
20,500	Metal Halide	1,200	$51.37	$63.97
36,000	Metal Halide	1,856	$61.29	$76.32
5,800	Sodium - Colonial Post Top	344	$26.55	$33.06

Appendix 4 - Updates & Corrections
Schedule C Sheet 3 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates

Area Lighting

Service Classification No. 5 - P.S.C. No. 15

Decorative and Specialty Lighting

Lumens	Type	Annual kWhrs	Present Monthly Base Rate	Proposed Monthly Base Rate
5,800	Sodium - Acorn	344	$20.52	$25.55
6,000	Induction - Acorn	340	$26.99	$33.61
14,000	Metal Halide - Acorn	820	$20.49	$25.52
16,000	Sodium - Victorian	721	$21.22	$26.42
27,000	Sodium - Highway Setback	1,264	$19.41	$24.17
50,000	Sodium - Highway Setback	1,984	$18.17	$22.63
20,500	Metal Halide - Highway Setback	1,200	$21.51	$26.79
36,000	Metal Halide - Highway Setback	1,856	$24.30	$30.26
27,000	Sodium - Teardrop	1,264	$36.58	$45.55
50,000	Sodium - Teardrop	1,984	$40.87	$50.89
20,500	Metal Halide - Teardrop	1,200	$37.95	$47.26
36,000	Metal Halide - Teardrop	1,856	$40.96	$51.01

Decorative and Specialty Lighting - Supporting Equipment

Type	Present Monthly Base Rate	Proposed Monthly Base Rate
Standard Wooden Utility Pole	$12.67	$15.78
Fluted Decorative Fiberglass Pole (area lighting)	$41.39	$51.54
Fiberglass Pole up to 20' (decorative other than highway)	$36.64	$45.63
Fiberglass Pole for Highway Setback (30' mounting height)	$36.64	$45.63
Decorative Arm for Decorative Teardrop Lighting	$17.61	$21.93

Appendix 4 - Updates & Corrections
Schedule C Sheet 4 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates

Public Street and Highway Lighting

Service Classification No. 8 - P.S.C. No. 15

Company Owned and Maintained

Lumens	Type	Annual kWh	Present Annual Base Rate	Proposed Annual Base Rate
Standard Lights				
5,800	Sodium Vapor	344	$231.79	$262.25
16,000	Sodium Vapor	720	$257.62	$291.47
27,000	Sodium Vapor	1,264	$312.37	$353.41
50,000	Sodium Vapor	1,984	$352.25	$398.53
140,000	Sodium Vapor	4,656	$583.31	$659.95
20,500	Metal Halide	1,200	$355.35	$402.04
36,000	Metal Halide	1,856	$344.85	$390.16
LED Lights				
3,600	LED	156	$183.58	$207.70
7,200	LED	328	$207.94	$235.26
10,000	LED	372	$252.94	$286.18
17,600	LED	612	$374.64	$423.87
2,900	LED	100	$187.88	$212.57
6,800	LED	260	$196.71	$222.56
9,500	LED	380	$225.30	$254.90
16,500	LED	620	$299.15	$338.46
3,000	LED	120	$141.37	$159.95
2,000	LED	80	$160.97	$182.12
5,250	LED	212	$168.53	$190.67
7,500	LED	300	$193.04	$218.40
13,000	LED	520	$256.31	$289.99
17,750	LED	712	$305.17	$345.27
27,500	LED	1,100	$377.04	$426.58
Non-Standard Lights				
1,000	Incandescent	368	$187.12	$211.71
2,500	Incandescent	756	$247.50	$280.02
4,000	Incandescent	1,180	$296.95	$335.97
6,000	Incandescent	1,620	$340.19	$384.89
3,600	Mercury Vapor	504	$238.12	$269.41
7,000	Mercury Vapor	832	$257.86	$291.74
11,000	Mercury Vapor	1,184	$279.73	$316.49
15,000	Mercury Vapor	1,820	$326.36	$369.24
20,000	Mercury Vapor	1,820	$326.36	$369.24
60,000	Mercury Vapor	4,320	$478.82	$541.74
Lamp, Fixture and Pole Package				
5,800	Sodium Vapor - Colonial Post Top	344	$501.65	$567.57
5,800	Sodium Vapor	344	$632.39	$715.48
16,000	Sodium Vapor	720	$655.51	$741.64
14,000	Metal Halide	820	$722.52	$817.46
20,500	Metal Halide	1,200	$746.73	$844.85
36,000	Metal Halide	1,856	$790.71	$894.61
Standard Decorative and Special Purpose Luminaires				
5,800	Sodium Vapor - Acorn	344	$293.26	$331.79
6,000	Induction - Acorn	340	$397.77	$450.04
14,000	Metal Halide - Acorn	820	$371.15	$419.92
16,000	Sodium Vapor - Victorian	720	$377.88	$427.53
27,000	Sodium Vapor - Highway Setback	1,264	$358.56	$405.67
50,000	Sodium Vapor - Highway Setback	1,984	$403.13	$456.10
20,500	Metal Halide - Highway Setback	1,200	$410.82	$464.80
36,000	Metal Halide - Highway Setback	1,856	$400.07	$452.64
50,000	Sodium Vapor - Floodlight	1,984	$373.08	$422.10
36,000	Metal Halide - Floodlight	1,856	$357.58	$404.56
110,000	Metal Halide - Floodlight	4,400	$614.27	$694.98
27,000	Sodium Vapor - Teardrop	1,264	$431.97	$488.73
50,000	Sodium Vapor - Teardrop	2,480	$506.72	$573.30
20,500	Metal Halide - Teardrop	1,200	$468.06	$529.56
36,000	Metal Halide - Teardrop	1,856	$479.80	$542.84
1,500	LED	60	$221.96	$251.12
2,500	LED	100	$337.09	$381.38
8,000	LED	320	$272.06	$307.81
15,250	LED	612	$380.33	$430.30
25,750	LED	1,032	$465.79	$526.99
12,000	LED	480	$761.46	$861.51
16,001	LED	640	$636.71	$720.37

Appendix 4 - Updates & Corrections
Schedule C Sheet 5 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates

Public Street and Highway Lighting

Service Classification No. 8 - P.S.C. No. 15

Customer Owned/Company Maintained

Lumens	Type	Annual kWh	Present Annual Base Rate	Proposed Annual Base Rate
Standard Lights				
6,000	Induction	340	$69.07	$78.15
5,800	Sodium Vapor	344	$78.76	$89.11
16,000	Sodium Vapor	720	$101.30	$114.61
27,000	Sodium Vapor	1,264	$133.88	$151.47
50,000	Sodium Vapor	1,984	$177.64	$200.98
140,000	Sodium Vapor	4,656	$347.60	$393.27
14,000	Metal Halide	820	$114.76	$129.84
20,500	Metal Halide	1,200	$138.70	$156.92
36,000	Metal Halide	1,856	$174.01	$196.87
108,000	Metal Halide	4,400	$370.22	$418.87
Non-Standard Lights				
9,500	Sodium Vapor	584	$93.16	$105.40
1,000	Incandescent	368	$115.59	$130.78
2,500	Incandescent	756	$153.23	$173.36
4,000	Incandescent	1,180	$180.09	$203.75
6,000	Incandescent	1,620	$233.80	$264.52
10,000	Incandescent	2,480	$285.37	$322.87
7,000	Mercury Vapor	832	$106.86	$120.90
11,000	Mercury Vapor	1,184	$128.53	$145.42
15,000	Mercury Vapor	1,820	$172.44	$195.10
20,000	Mercury Vapor	1,820	$172.44	$195.10
60,000	Mercury Vapor	4,320	$324.01	$366.58

Other Charges

Type	Present* Base Rate	Proposed Base Rate
Pre-attachment survey fee	$12.69	$14.36
Annual pole rental (solely for street lighting)	$86.69	$98.08
Annual pole rental (company sole owned)	$9.94	$11.25
Annual pole rental (company joint owned)	$4.95	$5.60

Appendix 4 - Updates & Corrections
Schedule C Sheet 6 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Present and Proposed Electric Rates

Public Street and Highway Lighting

Service Classification No. 8 - P.S.C. No. 15

Company Owned and Maintained

Lumens	Type	Annual kWh	Present Annual Base Rate	Proposed Annual Base Rate
Standard Lights				
5,800	Sodium Vapor	344	$34.98	$39.58
9,500	Sodium Vapor	584	$49.41	$55.90
16,000	Sodium Vapor	720	$57.55	$65.11
27,000	Sodium Vapor	1,264	$90.17	$102.02
50,000	Sodium Vapor	1,984	$133.32	$150.84
140,000	Sodium Vapor	4,656	$293.50	$332.06
8,500	Metal Halide	520	$45.56	$51.55
14,000	Metal Halide	820	$63.57	$71.92
20,500	Metal Halide	1,200	$86.34	$97.68
36,000	Metal Halide	1,856	$125.62	$142.13
110,000	Metal Halide	4,400	$278.18	$314.73
Non-Standard Lights				
1,000	Incandescent	368	$36.43	$41.22
2,500	Incandescent	756	$59.73	$67.58
4,000	Incandescent	1,180	$85.13	$96.32
6,000	Incandescent	1,620	$111.53	$126.18
3,600	Mercury Vapor	504	$44.58	$50.44
7,000	Mercury Vapor	832	$64.26	$72.70
11,000	Mercury Vapor	1,184	$85.40	$96.62
20,000	Mercury Vapor	1,820	$123.50	$139.73
60,000	Mercury Vapor	4,320	$273.49	$309.43
6,000	Induction	340	$34.75	$39.32

Other Charges

Type	Present* Base Rate	Proposed Base Rate
Pre-attachment survey fee	$12.69	$14.36
Annual pole rental (solely for street lighting)	$86.69	$98.08
Annual pole rental (company sole owned)	$9.94	$11.25
Annual pole rental (company joint owned)	$4.95	$5.60

Public Street and Highway Lighting - Supporting Equipment

Type	Present* Base Rate	Proposed Base Rate
Standard Company Pole (street lighting)	$ 86.69	$ 98.08
Mastarms greater than 14'	$ 48.97	$ 55.40
Fluted Decorative Fiberglass Pole	$ 452.83	$ 512.33
Fiberglass Pole up to 20' (decorative lighting)	$ 401.34	$ 454.07
Fiberglass Pole for Highway Setback (30' mounting height)	$ 401.34	$ 454.07
Decorative Arm for Decorative Teardrop Lighting	$ 192.73	$ 218.05

Appendix 4 - Updates & Corrections
Schedule C Sheet 7 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Proposed Electric Merchant Function Charges

	Current Rates	12 Months Ending Jun-25 Rate Year
MFC Administration Charge per kWh		
S.C. No. 1 - Residential	$ 0.00142	$ 0.00087
S.C. No. 2 - Non Demand	$ 0.00209	$ 0.00127
S.C. No. 2 - Primary Demand	$ 0.00001	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00010	$ 0.00006
S.C. No. 3 - Large Power Primary	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00411	$ 0.00226
S.C. No. 6 - Residential Time-of-Use	$ 0.00065	$ 0.00066
S.C. No. 8 - Street Lighting	$ 0.00020	$ 0.00015
S.C. No. 9 - Traffic Signals	$ 0.00319	$ 0.00062
S.C. No. 13 - Substation	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -
MFC Supply Charge per kWh		
S.C. No. 1 - Residential	$ 0.00326	$ 0.00206
S.C. No. 2 - Non Demand	$ 0.00478	$ 0.00302
S.C. No. 2 - Primary Demand	$ 0.00002	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00022	$ 0.00015
S.C. No. 3 - Large Power Primary	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00941	$ 0.00536
S.C. No. 6 - Residential Time-of-Use	$ 0.00150	$ 0.00155
S.C. No. 8 - Street Lighting	$ 0.00046	$ 0.00035
S.C. No. 9 - Traffic Signals	$ 0.00731	$ 0.00148
S.C. No. 13 - Substation	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -

Appendix 4 - Updates & Corrections
Schedule C Sheet 8 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Low Income Bill Discount Program Credits

	Electric Heating		Electric Non-Heating	
Income Level	**Current**	**Proposed**	**Current**	**Proposed**
Tier 1	$ 42.91	$ 63.49	$ 42.91	$ 63.49
Tier 2	$ 54.04	$ 74.62	$ 54.04	$ 74.62
Tier 3	$ 73.61	$ 94.18	$ 73.61	$ 94.18
Tier 4	$ 67.75	$ 88.33	$ 67.75	$ 88.33

Appendix 4 - Updates & Corrections
Schedule C Sheet 9 of 9
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
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	Proposed Rates	
S.C. No. 1				
	Customer Charge	$ 19.50	$ 21.50	
	Contract Demand	$ 5.58	$ 4.69	per kW
	Daily As-Used Demand On-Peak	$ 0.42583	$ 0.51750	per kW
	Daily As-Used Demand Super-Peak	$ 0.17846	$ 0.20024	
S.C. No. 2 - Non Demand				
	Customer Charge	$ 30.50	$ 32.50	
	Contract Demand	$ 4.81	$ 7.57	per kW
	Daily As-Used Demand On-Peak	$ 0.42436	$ 0.44713	per kW
	Daily As-Used Demand Super-Peak	$ 0.14621	$ 0.20067	per kW
S.C. No. 2 - Secondary Demand				
	Customer Charge	$ 120.00	$ 140.00	
	Contract Demand	$ 1.97	$ 1.44	per kW
	Daily As-Used Demand On-Peak	$ 0.54396	$ 0.64535	per kW
	Daily As-Used Demand Super-Peak	$ 0.13960	$ 0.21832	per kW
S.C. No. 2 - Primary Demand				
	Customer Charge	$ 490.00	$ 530.00	
	Contract Demand	$ 3.15	$ 3.05	per kW
	Daily As-Used Demand On-Peak	$ 0.35017	$ 0.42230	per kW
	Daily As-Used Demand Super-Peak	$ 0.09804	$ 0.13337	per kW
S.C. No. 3				
	Customer Charge	$ 2,400.00	$ 2,600.00	
	Contract Demand	$ 3.52	$ 4.25	per kW
	Daily As-Used Demand On-Peak	$ 0.49173	$ 0.49092	per kW
	Daily As-Used Demand Super-Peak	$ 0.17971	$ 0.15108	per kW
S.C. No. 6				
	Customer Charge	$ 22.50	$ 24.50	
	Contract Demand	$ 5.89	$ 4.12	per kW
	Daily As-Used Demand On-Peak	$ 0.61821	$ 0.51952	per kW
	Daily As-Used Demand Super-Peak	$ 0.27940	$ 0.20170	
S.C. No. 13 - Substation				
	Customer Charge	$ 7,500.00	$ 8,500.00	
	Contract Demand	$ 0.98	$ 3.12	per kW
	Daily As-Used Demand On-Peak	$ 0.30770	$ 0.37578	per kW
	Daily As-Used Demand Super-Peak	$ 0.11298	$ 0.11931	per kW
S.C. No. 13 - Transmission				
	Customer Charge	$ 12,000.00	$ 13,500.00	
	Contract Demand	$ 1.17	$ 2.20	per kW
	Daily As-Used Demand On-Peak	$ 0.17589	$ 0.21406	per kW
	Daily As-Used Demand Super-Peak	$ 0.06002	$ 0.07128	per kW

Appendix 4 - Updates & Corrections
Schedule D Sheet 1 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Proposed Monthly Gas Base Delivery Rates

			Current Rates	12 Months Ending Jun-25 Rate Year
S.C. No. 1 & 12				
	Billing Block 1	First 2 Ccf	$ 24.25	$ 26.25
	Billing Block 2 per Ccf	Next 48 Ccf	$ 1.3625	$ 1.4812
	Billing Block 3 per Ccf	Additional	$ 0.9479	$ 1.2598
S.C. No. 2, 6 & 13				
	Billing Block 1	First 2 Ccf	$ 39.00	$ 41.00
	Billing Block 2 per Ccf	Next 98 Ccf	$ 0.5609	$ 0.6905
	Billing Block 3 per Ccf	Next 4900 Ccf	$ 0.5420	$ 0.6789
	Billing Block 4 per Ccf	Additional	$ 0.4805	$ 0.6404
	SC 6 High Volume	All Ccf above 2 Ccf	$ 0.3869	$ 0.5789
S.C. No. 11 Transmission	Customer Charge	First 1,000 Ccf	$ 4,800.00	$ 4,000.00
	Volumetric Charge per Ccf	Additional	$ 0.0189	$ 0.0231
	MDQ	Per Mcf of MDQ per Month	$ 9.23	$ 11.00
S.C. No. 11 Distribution	Customer Charge	First 1,000 Ccf	$ 2,100.00	$ 2,400.00
	Volumetric Charge per Ccf	Additional	$ 0.0404	$ 0.0500
	MDQ	Per Mcf of MDQ per Month	$ 21.35	$ 25.83
S.C. No. 11 DLM	Customer Charge	First 1,000 Ccf	$ 7,600.00	$ 7,100.00
	Volumetric Charge per Ccf	Additional	$ 0.0275	$ 0.0347
	MDQ	Per Mcf of MDQ per Month	$ 15.48	$ 17.99
S.C. No. 11 EG	Customer Charge		$ 2,000.00	$ 3,000.00
	MDQ	Per Mcf of MDQ per Month	$ 15.16	$ 17.99

Appendix 4 - Updates & Corrections
Schedule D Sheet 2 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E 0418 & 23-G-0419
Gas Commodity Related Merchant Function Charges
Twelve Months Ending June 30, 2025

		Current Rates	Proposed
MFC Administration Charge per Ccf			
MFC-1	1, 12 & 16	$ 0.00533	$ 0.00467
MFC-2	2, 6, 13 & 15	$ 0.00513	$ 0.00465
MFC Supply Charge per Ccf			
MFC-1	1, 12 & 16	$ 0.01208	$ 0.01239
MFC-2	2, 6, 13 & 15	$ 0.01163	$ 0.01234

Appendix 4 - Updates & Corrections
Schedule D Sheet 3 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Summary of Low Income Bill Discount Program Credits
Twelve Months Ended June 30, 2025

	Gas Heating		Gas Non-Heating	
Income Level	**Current**	**Proposed**	**Current**	**Proposed**
Tier 1	$ 22.99	$ 28.74	$ 3.00	$ 3.00
Tier 2	$ 42.68	$ 52.05	$ 3.00	$ 3.00
Tier 3	$ 57.48	$ 71.61	$ 3.00	$ 3.00
Tier 4	$ 51.76	$ 65.76	$ 3.00	$ 3.00

Appendix 4 - Updates & Corrections
Schedule E Sheet 1 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Electric Residential Typical Monthly Bill

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Avg kWh	**660**	**660**	**570**	**570**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 19.50	$ 21.50	$ 19.50	$ 21.50	
Energy Delivery $/kWh					
Delivery Chrg	$0.10546	$0.12749	$0.10546	$0.12749	
System Benefits Chrg	$0.00866	$0.00866	$0.00866	$0.00866	
MFC Admin Chrg	$0.00142	$0.00087	$0.00142	$0.00087	
Transition Adj Chrg	$0.00010	$0.00010	$0.00010	$0.00010	
Electric Bill Credit	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous II	$0.00731	$0.00731	$0.00731	$0.00731	
Purchased Power Adjustment	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous Charges	$0.00103	$0.00103	$0.00103	$0.00103	
MFC Supply Chrg	$0.00337	$0.00217	$0.00337	$0.00217	
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	$19.95	$22.00	$19.95	$22.00	
Energy Delivery					
Delivery	$71.21	$86.09	$61.50	$74.35	
MFC Admin Chrg	$0.96	$0.59	$0.83	$0.51	
Transition Adj Chrg	$0.07	$0.07	$0.06	$0.06	
EBC	$0.00	$0.00	$0.00	$0.00	
SBC	$5.85	$5.85	$5.05	$5.05	
Delivery Subtotal w/ Revenue Tax	$98.04	$114.60	$87.39	$101.97	
Energy Supply					
PPA	$0.00	$0.00	$0.00	$0.00	
MISC	$5.62	$5.62	$4.85	$4.85	
MPC	$56.74	$56.74	$49.00	$49.00	
MPA	($1.47)	($1.47)	($1.27)	($1.27)	
MFC Supply Chrg	$2.28	$1.47	$1.97	$1.27	
Energy Subtotal w/ Revenue Tax	$63.17	$62.36	$54.55	$53.85	
Low Income Bill Discount	$0.00	$0.00	$ (42.91)	$ (63.49)	(Tier 1 Discount)
Total Bill	**$161.21**	**$176.96**	**$99.03**	**$92.33**	

$ Total Delivery Increase	$15.75	($6.70)
% Total Delivery Increase	16.67%	-16.18%
$ Total Bill Increase	$15.75	($6.70)
% Total Bill Increase	9.77%	-6.77%

Appendix 4 - Updates & Corrections
Schedule E Sheet 2 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Electric Residential Typical Monthly Bill

Delivery Only				
Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	%
3	$ 20.33	$ 22.44	$ 2.11	10.4%
10	$ 21.22	$ 23.48	$ 2.27	10.7%
20	$ 22.49	$ 24.97	$ 2.49	11.1%
30	$ 23.76	$ 26.46	$ 2.71	11.4%
40	$ 25.02	$ 27.95	$ 2.93	11.7%
50	$ 26.29	$ 29.44	$ 3.15	12.0%
80	$ 30.10	$ 33.90	$ 3.80	12.6%
90	$ 31.36	$ 35.39	$ 4.02	12.8%
100	$ 32.63	$ 36.88	$ 4.24	13.0%
125	$ 35.80	$ 40.60	$ 4.79	13.4%
150	$ 38.97	$ 44.32	$ 5.34	13.7%
175	$ 42.14	$ 48.04	$ 5.89	14.0%
200	$ 45.31	$ 51.76	$ 6.44	14.2%
250	$ 51.66	$ 59.20	$ 7.54	14.6%
300	$ 58.00	$ 66.64	$ 8.64	14.9%
350	$ 64.34	$ 74.08	$ 9.74	15.1%
400	$ 70.68	$ 81.52	$ 10.84	15.3%
500	$ 83.36	$ 96.40	$ 13.03	15.6%
750	$ 115.07	$ 133.60	$ 18.53	16.1%
1,000	$ 146.77	$ 170.80	$ 24.02	16.4%
1,500	$ 210.18	$ 245.19	$ 35.01	16.7%
2,000	$ 273.60	$ 319.59	$ 46.00	16.8%
3,000	$ 400.42	$ 468.39	$ 67.97	17.0%
5,000	$ 654.06	$ 765.99	$ 111.93	17.1%
10,000	$ 1,288.18	$ 1,509.98	$ 221.81	17.2%

Total Bill				
Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	%
3	$ 20.59	$ 22.70	$ 2.11	10.2%
10	$ 22.09	$ 24.34	$ 2.25	10.2%
20	$ 24.23	$ 26.69	$ 2.46	10.2%
30	$ 26.37	$ 29.04	$ 2.67	10.1%
40	$ 28.51	$ 31.39	$ 2.88	10.1%
50	$ 30.65	$ 33.73	$ 3.08	10.1%
80	$ 37.07	$ 40.78	$ 3.71	10.0%
90	$ 39.21	$ 43.13	$ 3.91	10.0%
100	$ 41.35	$ 45.47	$ 4.12	10.0%
125	$ 46.70	$ 51.34	$ 4.64	9.9%
150	$ 52.05	$ 57.21	$ 5.16	9.9%
175	$ 57.40	$ 63.08	$ 5.68	9.9%
200	$ 62.75	$ 68.95	$ 6.20	9.9%
250	$ 73.45	$ 80.69	$ 7.23	9.8%
300	$ 84.15	$ 92.42	$ 8.27	9.8%
350	$ 94.85	$ 104.16	$ 9.31	9.8%
400	$ 105.56	$ 115.90	$ 10.35	9.8%
500	$ 126.96	$ 139.38	$ 12.42	9.8%
750	$ 180.46	$ 198.07	$ 17.61	9.8%
1,000	$ 233.96	$ 256.76	$ 22.79	9.7%
1,500	$ 340.97	$ 374.14	$ 33.17	9.7%
2,000	$ 447.97	$ 491.52	$ 43.54	9.7%
3,000	$ 661.99	$ 726.28	$ 64.29	9.7%
5,000	$ 1,090.01	$ 1,195.80	$ 105.79	9.7%
10,000	$ 2,160.07	$ 2,369.60	$ 209.53	9.7%

Appendix 4 - Updates & Corrections
Schedule E Sheet 3 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Comparison of Present and Proposed Electric Bills

S.C. No. 2 - Non Demand

	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	400	430	450	480	500	530	550	580	600
Present Bill	$ 104.91	$ 110.49	$ 114.20	$ 119.78	$ 123.50	$ 129.07	$ 132.79	$ 138.36	$ 142.08
Proposed Bill	$ 117.36	$ 123.72	$ 127.96	$ 134.32	$ 138.56	$ 144.92	$ 149.16	$ 155.52	$ 159.76
$ Increase	$ 12.45	$ 13.24	$ 13.76	$ 14.54	$ 15.07	$ 15.85	$ 16.37	$ 17.16	$ 17.68
% Increase	11.87%	11.98%	12.05%	12.14%	12.20%	12.28%	12.33%	12.40%	12.44%

Appendix 4 - Updates & Corrections
Schedule E Sheet 4 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Comparison of Present and Proposed Electric Bills

S.C. No. 2 - Secondary Demand

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 246.86	$ 271.54	$ 296.21	$ 394.92	$ 444.27					
Proposed Bill	$ 277.02	$ 301.67	$ 326.32	$ 424.91	$ 474.21					
Delivery Rate Increase	$ 30.16	$ 30.13	$ 30.10	$ 29.99	$ 29.94					
Total $ Increase	$ 30.16	$ 30.13	$ 30.10	$ 29.99	$ 29.94					
Total % Increase	12.22%	11.10%	10.16%	7.59%	6.74%					
10										
Present Bill	$ 324.12	$ 348.80	$ 373.47	$ 472.18	$ 521.53					
Proposed Bill	$ 364.45	$ 389.10	$ 413.75	$ 512.34	$ 561.64					
Delivery Rate Increase	$ 40.33	$ 40.30	$ 40.27	$ 40.16	$ 40.11					
$ Increase	$ 40.33	$ 40.30	$ 40.27	$ 40.16	$ 40.11					
% Increase	12.44%	11.55%	10.78%	8.51%	7.69%					
15										
Present Bill			$ 450.74	$ 549.44	$ 598.79	$ 845.55	$ 1,092.30			
Proposed Bill			$ 501.18	$ 599.77	$ 649.07	$ 895.55	$ 1,142.03			
Delivery Rate Increase			$ 50.44	$ 50.33	$ 50.28	$ 50.00	$ 49.73			
$ Increase			$ 50.44	$ 50.33	$ 50.28	$ 50.00	$ 49.73			
% Increase			11.19%	9.16%	8.40%	5.91%	4.55%			
20										
Present Bill				$ 626.70	$ 676.05	$ 922.81	$ 1,169.56	$ 1,416.32		
Proposed Bill				$ 687.20	$ 736.50	$ 982.98	$ 1,229.46	$ 1,475.94		
Delivery Rate Increase				$ 60.51	$ 60.45	$ 60.18	$ 59.90	$ 59.62		
$ Increase				$ 60.51	$ 60.45	$ 60.18	$ 59.90	$ 59.62		
% Increase				9.65%	8.94%	6.52%	5.12%	4.21%		
30										
Present Bill					$ 830.57	$ 1,077.33	$ 1,324.09	$ 1,570.84	$ 2,064.36	
Proposed Bill					$ 911.36	$ 1,157.85	$ 1,404.33	$ 1,650.81	$ 2,143.77	
Delivery Rate Increase					$ 80.79	$ 80.52	$ 80.24	$ 79.97	$ 79.42	
$ Increase					$ 80.79	$ 80.52	$ 80.24	$ 79.97	$ 79.42	
% Increase					9.73%	7.47%	6.06%	5.09%	3.85%	
40										
Present Bill						$ 1,231.85	$ 1,478.61	$ 1,725.36	$ 2,218.88	$ 2,712.39
Proposed Bill						$ 1,332.71	$ 1,579.19	$ 1,825.67	$ 2,318.64	$ 2,811.60
Delivery Rate Increase						$ 100.86	$ 100.58	$ 100.31	$ 99.76	$ 99.21
$ Increase						$ 100.86	$ 100.58	$ 100.31	$ 99.76	$ 99.21
% Increase						8.19%	6.80%	5.81%	4.50%	3.66%
50										
Present Bill						$ 1,386.37	$ 1,633.13	$ 1,879.89	$ 2,373.40	$ 2,866.91
Proposed Bill						$ 1,507.57	$ 1,754.05	$ 2,000.54	$ 2,493.50	$ 2,986.46
Delivery Rate Increase						$ 121.20	$ 120.93	$ 120.65	$ 120.10	$ 119.55
$ Increase						$ 121.20	$ 120.93	$ 120.65	$ 120.10	$ 119.55
% Increase						8.74%	7.40%	6.42%	5.06%	4.17%
100										
Present Bill						$ 2,158.98	$ 2,405.74	$ 2,652.49	$ 3,146.01	$ 3,639.52
Proposed Bill						$ 2,381.89	$ 2,628.37	$ 2,874.85	$ 3,367.82	$ 3,860.78
Delivery Rate Increase						$ 222.91	$ 222.64	$ 222.36	$ 221.81	$ 221.26
$ Increase						$ 222.91	$ 222.64	$ 222.36	$ 221.81	$ 221.26
% Increase						10.32%	9.25%	8.38%	7.05%	6.08%

Appendix 4 - Updates & Corrections
Schedule E Sheet 5 of 6
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Comparison of Present and Proposed Electric Bills

S.C. No. 2 - Primary Demand

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 596.43	$ 620.69	$ 644.96	$ 742.04	$ 790.57					
Proposed Bill	$ 641.06	$ 665.33	$ 689.60	$ 786.66	$ 835.19					
Delivery Rate Increase	$ 44.64	$ 44.64	$ 44.63	$ 44.62	$ 44.62					
Total $ Increase	$ 44.64	$ 44.64	$ 44.63	$ 44.62	$ 44.62					
Total % Increase	7.48%	7.19%	6.92%	6.01%	5.64%					
10										
Present Bill	$ 653.29	$ 677.56	$ 701.83	$ 798.91	$ 847.44					
Proposed Bill	$ 702.49	$ 726.76	$ 751.02	$ 848.09	$ 896.62					
Delivery Rate Increase	$ 49.20	$ 49.19	$ 49.19	$ 49.18	$ 49.18					
Total $ Increase	$ 49.20	$ 49.19	$ 49.19	$ 49.18	$ 49.18					
Total % Increase	7.53%	7.26%	7.01%	6.16%	5.80%					
15										
Present Bill			$ 758.70	$ 855.77	$ 904.31	$ 1,146.99	$ 1,389.68			
Proposed Bill			$ 812.45	$ 909.52	$ 958.05	$ 1,200.71	$ 1,443.36			
Delivery Rate Increase			$ 53.75	$ 53.74	$ 53.74	$ 53.71	$ 53.69			
Total $ Increase			$ 53.75	$ 53.74	$ 53.74	$ 53.71	$ 53.69			
Total % Increase			7.08%	6.28%	5.94%	4.68%	3.86%			
20										
Present Bill				$ 912.64	$ 961.18	$ 1,203.86	$ 1,446.55	$ 1,689.23		
Proposed Bill				$ 970.94	$ 1,019.47	$ 1,262.13	$ 1,504.79	$ 1,747.45		
Delivery Rate Increase				$ 58.30	$ 58.30	$ 58.27	$ 58.25	$ 58.22		
Total $ Increase				$ 58.30	$ 58.30	$ 58.27	$ 58.25	$ 58.22		
Total % Increase				6.39%	6.07%	4.84%	4.03%	3.45%		
30										
Present Bill					$ 1,074.91	$ 1,317.60	$ 1,560.28	$ 1,802.97	$ 2,288.33	
Proposed Bill					$ 1,142.33	$ 1,384.99	$ 1,627.65	$ 1,870.31	$ 2,355.62	
Delivery Rate Increase					$ 67.42	$ 67.39	$ 67.37	$ 67.34	$ 67.29	
Total $ Increase					$ 67.42	$ 67.39	$ 67.37	$ 67.34	$ 67.29	
Total % Increase					6.27%	5.11%	4.32%	3.73%	2.94%	
40										
Present Bill						$ 1,431.34	$ 1,674.02	$ 1,916.70	$ 2,402.07	$ 2,887.44
Proposed Bill						$ 1,507.84	$ 1,750.50	$ 1,993.16	$ 2,478.48	$ 2,963.80
Delivery Rate Increase						$ 76.51	$ 76.48	$ 76.46	$ 76.41	$ 76.36
Total $ Increase						$ 76.51	$ 76.48	$ 76.46	$ 76.41	$ 76.36
Total % Increase						5.35%	4.57%	3.99%	3.18%	2.64%
50										
Present Bill						$ 1,545.07	$ 1,787.76	$ 2,030.44	$ 2,515.81	$ 3,001.18
Proposed Bill						$ 1,630.70	$ 1,873.36	$ 2,116.02	$ 2,601.34	$ 3,086.65
Delivery Rate Increase						$ 85.63	$ 85.60	$ 85.58	$ 85.53	$ 85.48
Total $ Increase						$ 85.63	$ 85.60	$ 85.58	$ 85.53	$ 85.48
Total % Increase						5.54%	4.79%	4.21%	3.40%	2.85%
100										
Present Bill						$ 2,113.75	$ 2,356.44	$ 2,599.12	$ 3,084.49	$ 3,569.86
Proposed Bill						$ 2,244.98	$ 2,487.64	$ 2,730.30	$ 3,215.61	$ 3,700.93
Delivery Rate Increase						$ 131.22	$ 131.20	$ 131.17	$ 131.12	$ 131.07
Total $ Increase						$ 131.22	$ 131.20	$ 131.17	$ 131.12	$ 131.07
Total % Increase						6.21%	5.57%	5.05%	4.25%	3.67%

Appendix 4 - Updates & Corrections
Schedule E Sheet 6 of 6
Central Hudson Gas & Electric Corporation

Comparison of Present and Proposed Electric Rates
Cases 23-E-0418 & 23-G-0419
Rates Utilized in Development of Typical Bills
Rates in effect May 1, 2024

	SC 1	SC 2 ND	SC 2 SD	SC 2 PD	per kW SC 2 SD	per kW SC 2 PD
Market Price Charge	$ 0.08579	$ 0.08579	$ 0.08579	$0.08531		
Market Price Adjustment	$ (0.00222)	$ (0.00222)	$ (0.00222)	$0.00037		
Purchased Power Adjustment	$ -	$ -	$ -	$ -		
Miscellaneous Charges*	$ 0.00103	$ 0.00103	$ 0.00103	$ 0.00103	$0.16	$0.07
System Benefits Charge**	$ 0.00866	$ 0.00866	$ 0.00866	$ 0.00866		
MFC Admin Charge****	$ 0.00142	$ 0.00209	$ 0.00010	$ 0.00001		
MFC Supply Charge****	$ 0.00337	$ 0.00541	$ 0.00039	$ 0.00005		
MFC Transition Adjustment****	$ 0.00010	$ 0.00050	$ 0.00008	$ 0.00001		
EAM/RAM	$ 0.00512	$ 0.00480	$ -	$ -	$2.55	$1.49
Electric Bill Credit****	$ -	$ -	$ -	$ -		
DLM	$ 0.00001	$ 0.00001	$ -	$ -		
VDER CR	$ 0.00218	$ 0.00707				
	$ 0.00447	$ 0.00587	$ 0.02184	$ 0.27171		
Weighted Revenue Tax - Commodity	0.208%	0.208%	0.208%	0.208%		
Weighted Revenue Tax - Delivery	2.258%	0.208%	0.208%	0.208%		
MFC Admin Charge - Proposed	$ 0.00087	$ 0.00127	$ 0.00006	$ 0.00001		
MFC Supply Charge - Proposed***	$ 0.00217	$ 0.00365	$ 0.00032	$ 0.00004		
Electric Bill Credit - Proposed	$ -	$ -	$ -	$ -		

*Includes MISC II.

**In order to only show the impact of base rate increases, bills under proposed rates do not reflect changes to the DLM VDER CR, SBC, EAM and RAM. These items have been included at current rates but are subject to change.

***The MFC Supply Charge includes 50 percent of forecast net lost revenues associated with customer migration and therefore is subject to change each year based on the calculation of actual net lost revenues. Current allocation of MFC Lost Revenue Charge included in Proposed MFC Supply.

Market Price Charge, Market Price Adjustment, and Miscellaneous Charges are included using a 12 month average of June 2023 - May 2024

Appendix 4 - Updates & Corrections
Schedule F Sheet 1 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Average Annual Residential Gas Heating Customer Bill Impact
Twelve Months Ended June 30, 2025

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Block 1 Ccf	24	24	24	24	
Block 2 Ccf	406	406	387	387	
Block 3 Ccf	349	349	260	260	
Total Annual Ccf	**780**	**780**	**750**	**750**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 24.25	$26.25	$ 24.25	$ 26.25	
Gas Delivery Charges $/Ccf					
Next	$1.36250	$1.48120	$1.36250	$1.48120	
Next	$0.94790	$1.25980	$0.94790	$1.25980	
System Benefits Charge	$0.00000	$0.00000	$0.00000	$0.00000	
MFC Admin Charge	$0.00533	$0.00467	$0.00533	$0.00467	
Transition Adj Charge	$0.00372	$0.00372	$0.00372	$0.00372	
Miscellaneous	$0.03021	$0.03021	$0.03021	$0.03021	
Gas Bill Credit	$0.00000	$0.00000	$0.00000	$0.00000	
Gas Supply Charges $Ccf					
MFC Supply Charge	$0.01208	$0.01239	$0.01208	$0.01239	
Gas Supply Charge	$0.44852	$0.44852	$0.44852	$0.44852	
Rev Tax Factor					
Weighted Rev Tax - Commodity	0.00522	0.00522	0.00522	0.00522	
Weighted Rev Tax - Delivery	0.02522	0.02522	0.02522	0.02522	
CHG&E Bill			LOW INCOME		
Gas Delivery Charges:					
Basic Service Charge	$298.53	$323.15	$298.53	$323.15	
Next	$567.49	$616.93	$540.93	$588.06	
Next	$339.38	$451.05	$252.83	$336.02	
System Benefits Charge	$0.00	$0.00	$0.00	$0.00	
MFC Admin Charge	$4.26	$3.74	$4.10	$3.59	
Transition Adj Charge	$2.98	$2.98	$2.86	$2.86	
Miscellaneous	$24.17	$24.17	$23.24	$23.24	
Gas Bill Credit	$0.00	$0.00	$0.00	$0.00	
Subtotal Delivery	$1,236.81	$1,422.01	$1,122.50	$1,276.93	
Gas Supply Charges:					
MFC Supply Charge	$9.67	$9.91	$9.29	$9.53	
Gas Supply Charge	$351.68	$351.68	$338.16	$338.16	
Subtotal Energy Supply	$361.35	$361.60	$347.45	$347.69	
Low Income Bill Discount	$0.00	$0.00	($275.88)	($344.88)	(Tier 1 Discount)
Total Bill	**$1,598.15**	**$1,783.60**	**$1,194.07**	**$1,279.73**	
$ Total Bill Increase		$185.45		$85.67	
% Total Bill Increase		11.60%		7.17%	

Appendix 4 - Updates & Corrections
Schedule F Sheet 2 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Gas Residential Typical Monthly Bill
Twelve Months Ended June 30, 2025

Delivery Only				
Monthly Ccf	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
2	$ 24.92	$ 26.97	$ 2.05	8.23%
4	$ 27.76	$ 30.05	$ 2.29	8.26%
6	$ 30.60	$ 33.14	$ 2.54	8.29%
8	$ 33.44	$ 36.22	$ 2.78	8.31%
10	$ 36.28	$ 39.30	$ 3.02	8.33%
15	$ 43.37	$ 47.00	$ 3.63	8.37%
20	$ 50.47	$ 54.71	$ 4.24	8.39%
25	$ 57.57	$ 62.41	$ 4.84	8.41%
30	$ 64.66	$ 70.12	$ 5.45	8.43%
35	$ 71.76	$ 77.82	$ 6.06	8.44%
40	$ 78.86	$ 85.52	$ 6.66	8.45%
50	$ 93.05	$ 100.93	$ 7.88	8.47%
60	$ 102.99	$ 114.07	$ 11.07	10.75%
80	$ 122.88	$ 140.34	$ 17.47	14.22%
100	$ 142.76	$ 166.62	$ 23.86	16.71%
130	$ 172.58	$ 206.03	$ 33.45	19.38%
170	$ 212.35	$ 258.58	$ 46.23	21.77%
200	$ 242.17	$ 297.99	$ 55.82	23.05%
300	$ 341.58	$ 429.36	$ 87.78	25.70%
1,000	$ 1,037.45	$ 1,348.96	$ 311.51	30.03%

Total Bill				
Monthly Ccf	Bill at Current Rates	Bill at Proposed RY 1 Rates	Over Current Amount	Over Current %
2	$ 25.88	$ 27.94	$ 2.05	7.92%
4	$ 29.69	$ 31.98	$ 2.29	7.73%
6	$ 33.49	$ 36.03	$ 2.54	7.57%
8	$ 37.29	$ 40.07	$ 2.78	7.45%
10	$ 41.09	$ 44.12	$ 3.02	7.35%
15	$ 50.60	$ 54.23	$ 3.63	7.17%
20	$ 60.11	$ 64.34	$ 4.24	7.05%
25	$ 69.61	$ 74.46	$ 4.84	6.96%
30	$ 79.12	$ 84.57	$ 5.45	6.89%
35	$ 88.63	$ 94.68	$ 6.06	6.83%
40	$ 98.13	$ 104.80	$ 6.66	6.79%
50	$ 117.15	$ 125.03	$ 7.88	6.73%
60	$ 131.91	$ 142.98	$ 11.07	8.40%
80	$ 161.43	$ 178.89	$ 17.47	10.82%
100	$ 190.94	$ 214.80	$ 23.86	12.50%
130	$ 235.22	$ 268.67	$ 33.45	14.22%
170	$ 294.26	$ 340.49	$ 46.23	15.71%
200	$ 338.54	$ 394.36	$ 55.82	16.49%
300	$ 486.14	$ 573.92	$ 87.78	18.06%
1,000	$ 1,519.31	$ 1,830.82	$ 311.51	20.50%

Appendix 4 - Updates & Corrections
Schedule F Sheet 3 of 3
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Gas Commercial Typical Monthly Bill
Twelve Months Ended June 30, 2025

Delivery Only				
Monthly Ccf	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	Over Current %
2	$ 39.28	$ 41.29	$ 2.01	5.12%
10	$ 44.09	$ 47.14	$ 3.06	6.93%
30	$ 56.12	$ 61.78	$ 5.67	10.10%
50	$ 68.14	$ 76.42	$ 8.28	12.14%
100	$ 98.20	$ 113.01	$ 14.80	15.07%
150	$ 127.32	$ 149.01	$ 21.69	17.04%
200	$ 156.43	$ 185.02	$ 28.58	18.27%
250	$ 185.55	$ 221.02	$ 35.47	19.12%
300	$ 214.66	$ 257.02	$ 42.36	19.74%
400	$ 272.89	$ 329.03	$ 56.15	20.57%
500	$ 331.12	$ 401.04	$ 69.93	21.12%
600	$ 389.34	$ 473.05	$ 83.71	21.50%
800	$ 505.80	$ 617.07	$ 111.27	22.00%
1,000	$ 622.26	$ 761.09	$ 138.84	22.31%
1,500	$ 913.40	$ 1,121.14	$ 207.74	22.74%
2,000	$ 1,204.54	$ 1,481.19	$ 276.65	22.97%
3,000	$ 1,786.82	$ 2,201.28	$ 414.47	23.20%
5,000	$ 2,951.37	$ 3,641.47	$ 690.10	23.38%
7,500	$ 4,252.52	$ 5,344.92	$ 1,092.40	25.69%
10,000	$ 5,553.66	$ 7,048.36	$ 1,494.71	26.91%
12,000	$ 6,594.57	$ 8,411.12	$ 1,816.55	27.55%
14,000	$ 7,635.49	$ 9,773.88	$ 2,138.39	28.01%
16,000	$ 8,676.40	$ 11,136.63	$ 2,460.24	28.36%
20,000	$ 10,758.23	$ 13,862.15	$ 3,103.92	28.85%

Total Bill				
Monthly Ccf	Bill at Current Rates	Bill at Proposed RY 1 Rates	Over Current Amount	Over Current %
2	$ 40.20	$ 42.21	$ 2.01	5.00%
10	$ 48.68	$ 51.74	$ 3.06	6.28%
30	$ 69.90	$ 75.57	$ 5.67	8.10%
50	$ 91.12	$ 99.39	$ 8.28	9.08%
100	$ 144.16	$ 158.96	$ 14.80	10.27%
150	$ 196.25	$ 217.94	$ 21.69	11.05%
200	$ 248.33	$ 276.92	$ 28.58	11.51%
250	$ 300.42	$ 335.90	$ 35.47	11.81%
300	$ 352.51	$ 394.88	$ 42.36	12.02%
400	$ 456.69	$ 512.84	$ 56.15	12.29%
500	$ 560.87	$ 630.80	$ 69.93	12.47%
600	$ 665.05	$ 748.76	$ 83.71	12.59%
800	$ 873.41	$ 984.68	$ 111.27	12.74%
1,000	$ 1,081.77	$ 1,220.60	$ 138.84	12.83%
1,500	$ 1,602.66	$ 1,810.40	$ 207.74	12.96%
2,000	$ 2,123.55	$ 2,400.20	$ 276.65	13.03%
3,000	$ 3,165.34	$ 3,579.81	$ 414.47	13.09%
5,000	$ 5,248.92	$ 5,939.02	$ 690.10	13.15%
7,500	$ 7,698.83	$ 8,791.23	$ 1,092.40	14.19%
10,000	$ 10,148.74	$ 11,643.45	$ 1,494.71	14.73%
12,000	$ 12,108.68	$ 13,925.22	$ 1,816.55	15.00%
14,000	$ 14,068.61	$ 16,207.00	$ 2,138.39	15.20%
16,000	$ 16,028.54	$ 18,488.77	$ 2,460.24	15.35%
20,000	$ 19,948.40	$ 23,052.32	$ 3,103.92	15.56%

Appendix 4 - Updates & Corrections
Schedule G Sheet 1 of 2
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Illustrative Example of Make Whole Provision - Electric

	Jul-24			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	260,373	174,200,300		$ 19.50	$ 0.10546	$ 0.00468	$ -		$ 21.50	$ 0.12749	$ 0.00293	$ -		$ 4,053,528
SC 2 Non Demand	32,898	15,762,037		$ 30.50	$ 0.07234	$ 0.00687	$ -		$ 32.50	$ 0.10099	$ 0.00429	$ -		$ 476,712
SC 2 Secondary	11,355	125,344,322	379,831	$ 120.00	$ 0.00467	$ 0.00032	$ -	$ 12.71	$ 140.00	$ 0.00467	$ 0.00021	$ -	$ 14.74	$ 984,369
SC 2 Primary	150	19,465,000	55,614	$ 490.00	$ 0.00144	$ 0.00003	$ -	$ 9.79	$ 530.00	$ 0.00144	$ 0.00002	$ -	$ 10.70	$ 56,426
SC 3 Primary	32	26,752,000	60,800	$ 2,400.00			$ -	$ 12.56	$ 2,600.00		$ -	$ -	$ 13.54	$ 65,984
SC 5 Area Lighting **	3,731	810,000		$ 216,300.00		$ 0.01352	$ -		$ 269,340.00		$ 0.00762	$ -		$ 53,040
SC 6 Residential TOU 12 Hour on pk^^	1,130	484,000		$ 22.50	$ 0.13826	$ 0.00215	$ -		$ 24.50	$ 0.16258	$ 0.00221	$ -		$ 14,060
SC 6 Residential TOU 12 Hour off pk^^		396,000			$ 0.04612	$ 0.00215	$ -			$ 0.05419	$ 0.00221	$ -		$ 3,219
SC 6 Residential TOU 5 Hour on pk				$ 22.50	$ 0.10987	$ 0.00215	$ -		$ 24.50	$ 0.13477	$ 0.00221	$ -		
SC 6 Residential TOU 5 Hour off pk					$ 0.09501	$ 0.00215	$ -			$ 0.11654	$ 0.00221	$ -		
SC 8 Street Lighting **	209	700,000		$ 414,487.00		$ 0.00066	$ -		$474,753		$ 0.00050	$ -		$ 60,266
SC 9 Traffic Signals	59	60,000		$ 4.26		$ 0.01050	$ -		$ 4.97		$ 0.00210	$ -		$ (462)
SC 13 Substation	6	10,024,900	16,828	$ 7,500.00			$ -	$ 10.11	$ 8,500.00		$ -	$ -	$ 10.93	$ 19,799
SC 13 Transmission	6	57,917,303	93,462	$ 12,000.00			$ -	$ 5.95	$ 13,500.00		$ -	$ -	$ 6.55	$ 65,077
Total														**$ 5,852,020**

^^ 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.

Appendix 4 - Updates & Corrections
Schedule G Sheet 2 of 2
Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Illustrative Example of Make Whole Provision - Gas

	Jul-24			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	75,622	13,815		$ 24.25			$ -		$ 26.25			$ -		$ 151,244
Block 2		100,567			$ 1.36250					$ 1.4812				$ 119,373
Block 3		7,459			$ 0.94790					$ 1.2598				$ 23,265
MFC						$ 0.01741					$ 0.01706			$ (426)
Gas Bill Credit														$ -
SC 2/6/13 Non-Residential														
Block 1	12,794	1,606		$ 39.00			$ -		$ 41.00			$ -		$ 25,588
Block 2		36,497			$ 0.56090					$ 0.6905				$ 47,300
Block 3		103,157			$ 0.54200					$ 0.6789				$ 141,187
Block 4		33,629			$ 0.48050					$ 0.6404				$ 53,756
SC 6 High Volume		47,668			$ 0.38690					$ 0.5789				$ 91,538
MFC						$ 0.01676					$ 0.01699			$ 402
Gas Bill Credit														$ -
SC 11 DLM														
Customer Charge - First 1,000 ccf	1			$ 7,600.00			$ -		$ 7,100.00			$ -		
Block 1		100			$ 0.02750					$ 0.0347				$ (500)
Block 2		28,655												$ 2,056
MDQ			4,900					$ 15.48					$ 17.99	$ 12,299
Gas Bill Credit														$ -
SC 11 D														
Customer Charge - First 1,000 ccf	4			$ 2,100.00			$ -		$ 2,400.00			$ -		
Block 1		320			$ 0.04040					$ 0.0500				$ 1,200
Block 2		18,630												$ 1,800
MDQ			4,752					$ 21.35					$ 25.83	$ 21,289
Gas Bill Credit														$ -
SC 11 T														
Customer Charge - First 1,000 ccf	2			$ 4,800.00			$ -		$ 4,000.00			$ -		
Block 1		200			$ 0.01890					$ 0.0231				$ (1,600)
Block 2		40,060												$ 1,683
MDQ			8,548					$ 9.23					$ 11.00	$ 15,130
Gas Bill Credit														$ -
SC 11 EG														
Customer Charge	2			$ 2,000.00					$ 3,000.00					$ 2,000
MDQ			10,000					$ 15.16					$ 17.99	$ 28,300
Total														**$ 736,883**

Central Hudson Gas & Electric Corporation
Cases 23-E-0418 & 23-G-0419
Revenue Matching Factors

	Recommended Decision as Updated & Corrected	Central Hudson Exceptions
ELECTRIC:		
Research & Development:		
Rate Allowance ($000)	$3,725	$3,725
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	5,120,144	5,120,144
Revenue Matching Factor - $/kWh	$0.000728	$0.000728
Pension Plan:		
Rate Allowance ($000)	($15,804)	($15,752)
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	5,120,144	5,120,144
Revenue Matching Factor - $/kWh	($0.003087)	($0.003076)
OPEBs:		
Rate Allowance ($000)	($6,022)	($6,018)
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	5,120,144	5,120,144
Revenue Matching Factor - $/kWh	($0.001176)	($0.001175)

	Recommended Decision as Updated & Corrected	Central Hudson Exceptions
GAS:		
Research & Development:		
Rate Allowance ($000)	$800	$800
SC 1, 2, 6, 12 & 13 Sales (Mcf)	13,195,615	13,195,615
Revenue Matching Factor - $/Mcf	$0.060626	$0.060626
Pension Plan:		
Rate Allowance ($000)	($4,481)	($4,451)
SC 1, 2, 6, 12 & 13 Sales (Mcf)	13,195,615	13,195,615
Revenue Matching Factor - $/Mcf	($0.339583)	($0.337309)
OPEBs:		
Rate Allowance ($000)	($1,708)	($1,700)
SC 1, 2, 6, 12 & 13 Sales (Mcf)	13,195,615	13,195,615
Revenue Matching Factor - $/Mcf	($0.129437)	($0.128831)

Central Hudson Gas & Electric Corporation
Case 23-E-0418 & Case 23-G-0419

Listing of Deferrals

Deferral Item	Deferral Method	Carrying Charges
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
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 Order 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, subject to carrying charges at the other customer capital rate.	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
Cloud Based or SaaS solutions implemented	Deferral of the revenue requirement effect (depreciation and return on investment) of variations resulting from software solutions chosen that require a different accounting treatment than that assumed in the establishment of revenue requirements. Further detail is provided in the Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan in Cases 20-E-0428 and 20-G-0429.	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 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
Earnings Adjustment Mechanisms - Electric	Authorization to recover from customers incentives earned related to earnings adjustment mechanisms targets met.	Not applicable
Earnings Adjustment Mechanisms - Gas	Authorization to recover from customers incentives earned related to earnings adjustment mechanisms targets met.	Not applicable
Economic Development	Deferral of rate allowance and actual expenditures and subject to carrying charges.	Pre-tax Authorized Rate of Return
Energy Efficiency - Electric & Gas	In accordance with the Order in Case 18-M-0084, as amended by 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, with the ability to defer overspending capped at the cumulative NENY budgets plus that afforded in the Order in Case 18-M-0084.	Pre-tax Authorized Rate of Return
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 - 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

Central Hudson Gas & Electric Corporation
Case 23-E-0418 & Case 23-G-0419

Listing of Deferrals

Deferral Item	Deferral Method	Carrying Charges
EV - Fast Charge Incentive	In accordance with Case 18-E-0138, 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. Amounts spent to fund the fast charging stations annual incentive payments will be deferred as a reduction of this balance.	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 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 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
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
External Rate Case Expenses	Deferral of external expenses as incurred up to cumulative three year rate allowance with amortization over 36 months with no true-up.	Not applicable
FAS 109	Deferral of tax on basis differences not provided for elsewhere.	Not applicable
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.	Pre-tax Authorized Rate of Return
FEMA Grant Microgrid Project	Deferral of the revenue requirement effect of the Company's funds not reimbursed for phase 1 and 2 of the project	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
Heat Pump Program	In accordance with the Order in Case 18-M-0084, as amended by 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, with the ability to defer overspending capped at the cumulative NENY budgets plus that afforded in the Order in Case 18-M-0084.	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).	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
Long Term Debt - Variable Rate NYSERDA Series B Bond	Deferral and amortization of the costs associated with the refinancing of this Bond should it occur during the rate plan.	Not applicable
Long Term Debt Interest Costs - Existing Variable Rate Debt	Deferral of interest costs over / under rate allowance	Pre-tax Authorized Rate of Return
Long Term Debt Interest Costs - Variable Issuances (Interest Costs on New Issuances of Long-Term Debt)	Deferral of long-term debt cost rate of new debt and actual embedded average cost rate of long-term debt will be reconciled to the forecasted rates reflected in rates.	Pre-tax Authorized Rate of Return
Lost Revenues (Finance Charges and Reconnection Fee Revenues)	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 if the impact is greater than 10 BPs of return on common equity for either gas department or electric department.	Pre-tax Authorized Rate of Return

Central Hudson Gas & Electric Corporation
Case 23-E-0418 & Case 23-G-0419

Listing of Deferrals

Deferral Item	Deferral Method	Carrying Charges
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
Major Storm Reserve	Deferral of incremental major storm restoration or prestaging costs as described in the Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan in Cases 20-E-0428 and 20-G-0429 (also attached as Appendix 5, Schedule C to the Company's Brief on Exceptions)	Pre-tax Authorized Rate of Return
Net Lost Revenues - Merchant Function Charge	Deferral of actual lost revenues over / under amount forecasted in rates due to migration to Non-RDM classes.	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
PSC initiated or Required Management or Operational Audit	Deferral of incremental costs incurred as a result of any Commission mandated management or operational 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 Moderator - Electric	Deferral of the net remaining regulatory liabilities resulting from previous rate cases available for future rate moderation.	Pre-tax Authorized Rate of Return
Rate Moderator - Gas	Deferral of the net remaining regulatory liabilities resulting from previous rate cases available for future rate moderation.	Pre-tax Authorized Rate of Return
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
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
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
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
Stray Voltage Expenses	Deferral of actual costs over / under rate allowance	Pre-tax Authorized Rate of Return
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 asset sale to TRANSCO carrying charges	Under the terms of Case 22-E-0077, Central Hudson transferred easements and transmission property to NY Transco with the proceeds of selling the easements to benefit customers.	Pre-tax Authorized Rate of Return

Central Hudson Gas & Electric Corporation
Case 23-E-0418 & Case 23-G-0419

Listing of Deferrals

Deferral Item	Deferral Method	Carrying Charges
AMP Phase I	Under terms of Case 20-M-0479, Central Hudson shall recover AMP Phase I costs (and related carrying charges) through a surcharge on customer bills, beginning August 1, 2022.	Pre-tax Authorized Rate of Return
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
Proceeding to Review Utilities' Diversity, Equity, and Inclusion Practices (Case 22-M-0314)	Under the terms of Case 22-M-0314 - Proceeding to Review Utilities' Diversity, Equity, and Inclusion Practices Order Initiating Proceeding 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
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
Climate Change Vulnerability Study Climate Change Resilience Plan (PSL 66, Subdivision 29; Case 22-E-0222)	Deferral of costs associated with the Central Hudson's Climate Change Vulnerability Study and a Climate Change Resilience Plan in accordance with PSL 66, Subdivision 29 and Case 22-E-0222. Recovery in accordance with developments in the generic proceeding.	Pre-tax Authorized Rate of Return
Management Audit Implementation Plan Costs (Case 21-M-0541)	Deferral of incremental costs not included in the development of revenue requirements incurred as a result of implementing Commission approved Management Audit Implementation Plans.	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
Roadway Excavation Quality Assurance Act	Deferral of incremental costs, including expenses and the revenue requirement effect (depreciation and return on capital) of capital costs from the impacts of the Roadway Excavation Quality Assurance Act.	Pre-tax Authorized Rate of Return

Central Hudson Exceptions

Governmental, Legislative and Other Regulatory Actions	Deferral of the revenue requirement effect of any governmental, legislative or other regulatory actions as described in the Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan in Cases 20-E-0428 and 20-G-0429.	Pre-tax Authorized Rate of Return
CATV Make Ready or 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.	Pre-tax Authorized Rate of Return
CLCPA Deferral	Deferral for future recovery of all incremental revenue requirement effects, including O&M, depreciation rate changes and return on and of capital, until such future time when these costs can be quantified and incorporated in rates.	Pre-tax Authorized Rate of Return

Notes:
(1) The above listing is intended to be an all-inclusive listing of the Company's current deferrals. However, to the extent any deferral provisions were inadvertently omitted, the Company reserves the right to revise this listing, which will be subject to Staff review and approval.

(2) The definition of incremental costs includes the return on and of (depreciation) capital investment, O&M expenses, Property Taxes, and any associated income tax effects.

Central Hudson Gas & Electric Corporation
Cases 23-E-0418
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 twelve months ending June 30, 2025 (the "Rate Year"), 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 an offset for 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 will be 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 Part 97). Except as otherwise provided herein, once the Commission definition of a major storm has been satisfied, 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 will be able to 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 (FEMA), New York State or any other reimbursement or proceeds received to cover such costs should be deducted from expenses charged to the Major Storm Reserve.

Central Hudson Gas & Electric Corporation
Cases 23-E-0418
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 will submit such retainer contracts to Staff.

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 its share (15%) of prestaging and mobilization costs in excess of $1.75M per event, and it will be subject to the Commission's 3-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 should identify costs broken out into major expense categories and capital. Central Hudson should 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.

Central Hudson Gas & Electric Corporation
Cases 23-E-0418
Major Storm Reserve

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.

Central Hudson Gas & Electric Corporation
Cases 23-E-0418 and 23-G-0419
Depreciation Factors and Rates

	ELECTRIC	Effective as of 7/1/21				Effective as of 7/1/24			
Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate	ASL	Curve Type	Net Salv. %	Annual Rate
HYDRO PRODUCTION									
331-00-1	STRUCTURES & IMPROVEMENTS	95	R2	-50	0.0158	95	R2	-50	0.0158
332-00-1	RESERVOIRS, DAMS	90	R3	-40	0.0156	95	R3	-60	0.0168
333-00-1	TURBINES & GENERATORS	80	R2.5	-60	0.0200	85	R2	-60	0.0188
334-10-1	ACCESSORY ELEC. EQUIP.	55	S0	-45	0.0264	55	R1	-25	0.0227
335-00-1	MISC. POWER PLANT EQUIP.	50	S1.5	-20	0.0240	55	S1.5	-20	0.0218
OTHER PRODUCTION									
341-00-1	STRUCTURES AND IMPROVEMENTS	55	R4	-15	0.0209	45	R2	-10	0.0244
342-00-1	FUEL HOLDERS, PRODUCERS & ACCESSORIES	55	R5	-15	0.0209	45	S0.5	-20	0.0267
343-00-1	PRIME MOVERS	25	R4	-10	0.0440	25	R4	-10	0.0440
344-00-1	GENERATORS	40	R2	-10	0.0275	30	R4	-15	0.0383
345-00-1	ACCESSORY ELECTRIC EQUIPMENT	35	R2.5	-20	0.0343	30	R1.5	-20	0.0400
346-00-1	MISCELLANEOUS POWER PLANT EQUIPMENT	35	S2.5	0	0.0286	30	S5	0	0.0333
TRANSMISSION									
350-11&15-1	LAND & LAND RIGHTS	90	R4	0	0.0111	85	R4	0	0.0118
350-13-1	LAND & LAND RIGHTS SUBSTATIONS	80	R4	0	0.0125	85	R4	0	0.0118
352-00-1	STRUCTURES & IMPROVEMENTS	80	R3	-15	0.0144	80	R3	-30	0.0163
353-11	STATION EQUIPMENT	52	R1.5	-20	0.0231	53	R1.5	-20	0.0226
353-12-1	SUPERVISORY EQUIPMENT- IN USE	32	L1.5	-20	0.0375	33	L1.5	-20	0.0364
353-20-1	SUPERVISORY EQUIPMENT- HELD	40	S0	-20	0.0300	45	S0.5	-20	0.0267
353-30-1	STATION EQUIP-ELECTRONIC	30	S2	-20	0.0400	30	S2	-20	0.0400
354-00-1	TOWERS & FIXTURES	80	R3	-30	0.0163	80	R3	-30	0.0163
355-00, 10 &15-1	POLES & FIXTURES	52	R2	-50	0.0288	55	R2	-70	0.0309
356-10-1	OVERHEAD COND. & DEVICES	70	R1.5	-35	0.0193	70	R2	-60	0.0229
356-15-1	OVERHEAD COND. & DEV. 345KV	65	R2	-40	0.0215	70	R2	-60	0.0229
356-20&25-1	OVERHEAD LINES, CLEARING	70	R3	-40	0.0200	75	R3	-60	0.0213
357-00-1	UNDERGROUND CONDUIT	41	R0.5	0	0.0244	41	R0.5	0	0.0244
358-00-1	UNERGROUND COND. & DEVICES	55	R3	-5	0.0191	60	R3	-15	0.0192
DISTRIBUTION									
360-11&22-1	LAND & LAND RIGHTS - OH	80	S4	0	0.0125	75	S4	0	0.0133
360-13 & 23-1	LAND & LAND RIGHTS - SUB & UND	70	S3	0	0.0143	75	S4	0	0.0133
361-00-1	STRUCTURES & IMPROVEMENTS	80	R3	-20	0.0150	75	R3	-30	0.0173
362-11-1	STATION EQUIPMENT-IN USE	54	S0.5	-25	0.0231	54	S0.5	-30	0.0241
362-12-1	SUPERVISORY EQUIPMENT	30	S0.5	-25	0.0417	30	S0.5	-25	0.0417
362-20-1	STATION EQUIPMENT-HELD	44	S1.5	-25	0.0284	45	S1.5	-30	0.0289
362-30-1	STATION EQUIP-ELECTRONICS	30	S0	-25	0.0417	20	S2	-30	0.0650
364-00-1	POLES & FIXTURES	56	R0.5	-40	0.0250	55	R0.5	-50	0.0273
365-10&20-1	OVHD. CONDUCTORS & DEVICES	70	R0.5	-40	0.0200	65	R0.5	-50	0.0231
366-11&22-1	UNDERGROUND CONDUIT	80	R4	-10	0.0138	80	R3	-55	0.0194
367-00-1	UNDERGROUND COND. & DEVICES	75	R3	-15	0.0153	70	R3	-40	0.0200
368-00-1	TRANSFORMERS	42	S0	-15	0.0274	42	R1	-20	0.0286
369-10-1	OVERHEAD SERVICES	65	R2	-65	0.0254	65	R2	-100	0.0308
*369-21&22-1	UNDERGROUND SERVICES	65	R2	-10	0.0169	65	R2	-40	0.0215
370-11&20-1	METERS & INSTALLATION	33	L0.5	0	0.0303	34	L0	0	0.0294
371-00-1	INSTALLATION ON CUST. PREMISES	24	R0.5	-20	0.0500	25	R0.5	-30	0.0520
372-10-1	LEASED PROP. ON CUST. PREMISES	8	L1.5	0	0.1250	8	L2	0	0.1250
373-00-1	STREET LIGHTS & CONDUCTORS	30	O1	-10	0.0367	30	O1	-15	0.0383
GENERAL PLANT									
390-00-1	STRUCTURES AND IMPROVEMENTS	40	R0.5	-30	0.0325	45	R0.5	-30	0.0289

Central Hudson Gas & Electric Corporation
Cases 23-E-0418 and 23-G-0419
Depreciation Factors and Rates

		Effective as of 7/1/21				Effective as of 7/1/24			
	GAS								
Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate	ASL	Curve Type	Net Salv. %	Annual Rate
TRANSMISSION									
365-11&20-2	LAND & LAND RIGHTS	75	R3	0	0.0133	70	R4	0	0.0143
366-20-2	STRUCTURES & IMPROVEMENTS	65	S1	-25	0.0192	55	S1	-25	0.0227
367-00-2	MAINS	85	R4	-25	0.0147	80	R4	-50	0.0188
369-11-2	STATION EQUIPMENT	40	L0	-25	0.0313	35	L1	-20	0.0343
369-12-2	SUPERVISORY EQUIPMENT	22	L1.5	-25	0.0568	22	L2	-20	0.0545
369-30-2	SUPERVISORY EQUIPMENT - ELECTRONIC	19	L2	-25	0.0658	25	S2	-20	0.0480
DISTRIBUTION									
374-11 & 13-2	LAND & LAND RIGHTS	85	R4	0	0.0118	75	R3	0	0.0133
375-00-2	STRUCTURES & IMPROVEMENTS	55	S1.5	-15	0.0209	65	S1.5	-40	0.0215
376-00-&11, 12,13-2	MAINS	95	R2.5	-45	0.0153	83	R2	-60	0.0193
378-11-2	STATION EQUIPMENT	36	L0.5	-45	0.0403	37	L0.5	-40	0.0378
378-12-2	SUPERVISORY EQUIPMENT	38	L0.5	-45	0.0382	35	S0	-40	0.0400
378-30-2	STATION EQUIP - ELECTRONIC					28	S2	-40	0.0500
380-00-2	SERVICES	81	R1.5	-60	0.0198	75	R1.5	-100	0.0267
381-00-2	METERS	28	L1.5	0	0.0357	24	L1	0	0.0417
382-00-2	METER INSTALLATIONS	28	L1.5	0	0.0357	24	L1	0	0.0417
385-00-2	INDUSTRIAL-STATION EQUIPMENT	45	R2	-30	0.0289	45	R2.5	-30	0.0289
385-10-2	INDUSTRIAL-STATION EQUIPMENT	40	S3.0	-30	0.0325	45	R4	-30	0.0289
	IROQUOIS TRANSMISSION								
365-50-2 ASL	LAND & LAND RIGHTS	70	R4	0	0.0143	70	R4	0	0.0143
365-50-2 RL	LAND & LAND RIGHTS- **original cost only fully amortized 12/31/2007**			0	0.0000			0	0.0000
366-50-2 ASL	STRUCTURES & IMPROVEMENTS	50	S1	-25	0.0250	55	S1	-25	0.0227
366-50-2 RL	STRUCTURES & IMPROVEMENTS- **original cost only fully amortized**			-55	0.0110			-25	0.0110
367-50-2 ASL	MAINS	80	R3	-25	0.0156	80	R3	-25	0.0156
367-50-2 RL	MAINS- **original cost only fully amortized**			-25	0.0031			-25	0.0031
369-51-2 ASL	STATION EQUIPMENT	40	L0	-25	0.0313	35	L1	-20	0.0343
369-51-2 RL	STATION EQUIPMENT -**original cost only fully amortized**			-25	0.0063			-20	0.0063
369-52-2 ASL	SUPERVISORY EQUIPMENT	22	L2	-25	0.0568	22	L1.5	-25	0.0000
369-52-2 RL	SUPERVISORY EQUIPMENT- **original cost only fully amortized**			-25	0.0132			-25	0.0000

Central Hudson Gas & Electric Corporation
Cases 23-E-0418 and 23-G-0419
Depreciation Factors and Rates

COMMON

		Effective as of 7/1/21				Effective as of 7/1/24			
Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate	ASL	Curve Type	Net Salv. %	Annual Rate
390-00-4	General Structures & Improvements	50	O1	-55	0.0310	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	10	L2.5	+10	0.0900	12	L2.5	+10	0.0750
392-20-4	Transportation Equip- Gas	10	L2.5	+10	0.0900	12	L2.5	+10	0.0750
392-40-4	Transportation Equip- Common	10	L2.5	+10	0.0900	12	L2.5	+10	0.0750
396-10-4	Power Operated Equip- Electric	12	L3	+10	0.0750	13	L2.5	+10	0.0692
396-20-4	Power Operated Equip- Gas	12	L3	+15	0.0708	13	L2.5	+15	0.0692
396-40-4	Power Operated Equip- Common	12	L3	+15	0.0708	13	L2.5	+15	0.0692

COMMON VINTAGE

Account	Account Description	ASL	Type	%	Rate	ASL	Type	%	Rate
391-11-4	EDP Equip- System and Main Frame	8	SQ	+0	0.1250	8	SQ	+0	0.1250
391-12-4	EDP- Systems Operations - SCADA	12	SQ	+0	0.0833	10	SQ	+0	0.0989
391-21-4	Data Handling Equipment	20	SQ	+0	0.0500	10	SQ	+0	0.1000
391-22-4	Office Furniture	20	SQ	+0	0.0500	15	SQ	+0	0.0667
393-00-4	Stores Equipment	35	SQ	+0	0.0286	25	SQ	+0	0.0400
393-20-4	Stores Equipment- Forklifts	35	SQ	+0	0.0286	25	SQ	+0	0.0400
394-10-4	Garage & Repair Equipment	30	SQ	+0	0.0333	25	SQ	+0	0.0355
394-20-4	Shop Equipment	30	SQ	+0	0.0333	25	SQ	+0	0.0180
394-30-4	Tools & Work Equipment	30	SQ	+0	0.0333	25	SQ	+0	0.0392
395-10-4	Laboratory Equipment	35	SQ	+0	0.0286	25	SQ	+0	0.0400
395-20-4	Laboratory Equipment- R&D	35	SQ	+0	0.0286	0	SQ	+0	0.0000
397-10-4	Communication Equipment - Radio	20	SQ	+0	0.0500	10	SQ	+0	0.1000
397-20-4	Communication Equipment - Telephone	10	SQ	+0	0.1000	10	SQ	+0	0.1000
398-00-4	Miscellaneous General Equipment	30	SQ	+0	0.0333	20	SQ	+0	0.0500