NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas and Electric Corporation for Electric Service	Case 17-E-0459

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JOINT PROPOSAL

April 18, 2018

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JOINT PROPOSAL

I. INTRODUCTION

This Joint Proposal ("Proposal" or "JP") for the resolution of all issues in the above-captioned cases is made mutually by Central Hudson Gas & Electric Corporation ("Central Hudson" or "Company"); the Staff of the Department of Public Service ("Staff"); Multiple Intervenors ("MI"); Pace Energy and Climate Center ("Pace"); New York Geothermal Energy Organization ("NY-GEO"); the Utility Intervention Unit of the Department of State, Division of Consumer Protection ("UIU"); Dutchess County; Acadia Center; the Public Utility Law Project of New York, Inc. ("PULP"); the Natural Resources Defense Council ("NRDC"); Bob Wyman; the U.S. Army Legal Services Agency, Representing the U.S. Department of Defense and All Other Federal Executive Agencies ("Army Legal Services") and the other entities whose signatures appear below (collectively, the "Signatories").

II. PROCEDURAL HISTORY

On June 17, 2015, the New York State Public Service Commission ("Commission" or "PSC") issued an Order Approving Rate Plan establishing a three-year rate plan for the Company for the period from July 1, 2015 through June 30, 2018 ("2015 Rate Plan").

On July 28, 2017, Central Hudson filed tariff leaves and testimony with the PSC in support of proposed increases to its electric and gas delivery revenues based on a rate year comprised of the 12 months ending June 30, 2019 ("Rate Year"). Central Hudson also included select financial information for two additional rate years as Attachment B to its filing letter.[1] Central Hudson's proposed delivery rates were designed to produce an electric delivery revenue increase of approximately $63.4 million and a gas delivery revenue increase of approximately $22.2 million, resulting in delivery revenue increases of 21.2% and 24.3%, respectively, or total bill increases of 12% and 18%, respectively, for an average residential customer.

On August 3, 2017, the Commission suspended the Company's proposed tariff leaves through December 24, 2017.[2] Discovery was commenced by Staff and other parties. To date, Staff has tendered a total of 839 multi-part information requests ("IRs")

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1 Cases 17-E-0459 et al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Cover Letter Attachment B (July 28, 2017).

2 Cases 17-E-0459 et al., Notice of Suspension of Effective Dates of the Major Rate Changes and Initiation of Proceedings (Aug. 3, 2017). By notices issued on August 3, 2017 and November 9, 2017 respectively, the Commission further suspended those tariffs through June 24, 2018. Cases 17-E-0459 et al., Notice of Suspension of Effective Date of Major Rate Changes and Initiation of Proceedings (Aug. 3, 2017); Cases 17-E-0459 et al., Notice of Suspension of Effective Date of Major Rate Changes and Initiation of Proceedings (Nov. 9. 2017).

to the Company; UIU tendered 86 IRs; and MI tendered 104 IRs. Various other parties also tendered more limited volumes of IRs to the Company.

Administrative Law Judges ("ALJs") Michelle L. Phillips and Erika Bergen were appointed to conduct the rate proceeding to review the Company's rate filing. On September 7, 2017, the ALJs convened a Procedural and Technical Conference during which, among other things, a litigation schedule was proposed and adopted in a subsequent ruling.[3] On September 20, 2017, the Company filed a motion requesting reconsideration of the Ruling on Schedule.[4] On September 29, 2017, the ALJs issued a ruling revising the litigation schedule.[5] To provide customers with an opportunity to comment on the Company's rate proposals, public statement hearings were held on: (1) October 3, 2017 in Poughkeepsie; (2) October 10, 2017 in Kingston; and (3) October 16, 2017 in Newburgh.

The Company filed supplemental testimony and exhibits on October 19, 2017. On November 21, 2017, Staff, UIU, MI, NRDC, PULP, Pace, and Dutchess County filed direct testimony. On November 22, 2017, Bard College, Bob Wyman and Citizens for Local Power ("CLP") filed direct testimony.

Consistent with the Commission's Settlement Guidelines[6] and Title 16 of the New York Codes, Rules and Regulations ("NYCRR"), Section 3.9, the Company filed with the

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3 Cases 17-E-0459 et al., Ruling on Schedule (Sept. 19, 2017).

4 Cases 17-E-0459 et al., Motion of Central Hudson Gas & Electric Corporation for Reconsideration of the Ruling on Schedule (Sept. 20, 2017).

5 Cases 17-E-0459 et al., Ruling on Motion for Reconsideration of Ruling on Schedule (Sept. 29, 2017).

6 32 NYPSC 71; Case 90-M-0255 et al., Proceeding on Motion of the Commission Concerning its Procedures for Settlement and Stipulation Agreements, filed in C11175, Opinion, Order and

Commission and served on all parties a Notice of Impending Settlement Negotiations on December 8, 2017.[7] Settlement negotiations began on December 21, 2017 and continued on January 4, 10, 11, 17, 18, 19, 22, 23, 24, 25, 30, 31, February 1, 2, 6, 8, 13, 14, 15, 16, 21, 28, March 7, and 8, 2018. Participants included representatives of the Company, Staff, Dutchess County, NY-GEO, MI, Pace, PULP, UIU, CLP and numerous other interested parties. Negotiations were held either in person with teleconference service also available or via teleconference. All settlement negotiations were subject to the Commission's Settlement Rules, 16 NYCRR Section 3.9, and the Commission's Settlement Guidelines.

On December 18, 2017, the Company, UIU, Pace, MI and CLP filed rebuttal testimony. On December 21, 2017, the Company filed a letter with the Commission consenting to an extension of the suspension period through and including July 24, 2018 in light of ongoing settlement negotiations, subject to a "make-whole" provision that would keep the Company and its customers in the same financial position they would have been absent the extension. On January 24, 2018, the Company filed another letter with the Commission consenting to an extension of the suspension period through and including August 23, 2018, subject to a "make-whole" provision. On January 25, 2018, a Ruling Granting Additional Postponement was issued revising the date on which evidentiary hearings in these cases would begin to March 6, 2018.[8]

Resolution Adopting Settlement Procedures and Guidelines, Opinion 92-2 (Mar. 24, 1991) ("Settlement Guidelines").

7 Cases 17-E-0459 et al., Notice of Impending Settlement Negotiations (Dec. 8, 2017).

8 Cases 17-E-0459 et al., Ruling Postponing Hearing and Revising Schedule (Dec. 22, 2017).

By letter dated February 20, 2018, the Company notified the Commission that Central Hudson, Staff and various parties had reached a tentative agreement to settle these cases and requested postponement of the evidentiary hearing. The Company also agreed to a further conditional 30-day extension of the suspension period through and including September 22, 2018 subject to a “make-whole” provision where the conditional extension would become null and void should a joint proposal be filed by March 15, 2018. On February 21, 2018, the ALJs issued a ruling further postponing the evidentiary hearing based on the Company’s filing.

The settlement negotiations were successful and have resulted in this JP between the Company, Staff, MI, Pace, NY-GEO, UIU, Dutchess County, Acadia Center, PULP, NRDC, Bob Wyman, Army Legal Services and other parties which is presented to the Commission for its consideration. The Signatories have developed a comprehensive set of terms and conditions for a three-year rate plan for Central Hudson’s electric and gas service. Pursuant to the settlement discussions, the Signatories recommend that the rates and surcharges of Central Hudson be determined in accordance with the following understandings, principles, qualifications, terms and conditions set forth in this JP and in the attached Appendices.

III. <u>TERM AND EFFECTIVE DATE OF RATE CHANGES</u>

The term of this JP is three years, commencing July 1, 2018 and continuing until June 30, 2021. The three successive 12-month periods, or Rate Years, ending on June 30 shall be referred to as “Rate Year 1,” “Rate Year 2,” and “Rate Year 3.” The JP sets out the terms for Rate Year 1 (July 1, 2018 through June 30, 2019). Rate Year 2 (July 1, 2019 through June 30, 2020) and Rate Year 3 (July 1, 2020 through June 30, 2021) will follow the same structure as Rate Year 1 at revenue and expense amounts agreed to by the Signatories and as set out in the JP and related appendices. The provisions of Rate Year 3 will, unless otherwise specified herein, remain in effect until superseding rates or terms become effective.

Nothing herein precludes Central Hudson from filing a new general electric or gas rate case prior to June 30, 2021, for rates to be effective on or after July 1, 2021. Except for minor rate changes and Commission-required rate changes permitted by Sections XXV.A of this JP, the Company will not initiate rate changes to become effective prior to July 1, 2021.

IV. REVENUE REQUIREMENTS

A. Revenue Requirements

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

B. Delivery Revenue Increases

The base delivery revenue increases are displayed in the table below. The increases reflect the revenue requirement effect of including Energy Efficiency Program Costs of $9.773 million and $1.182 million for electric and gas, respectively, in base rates.

Delivery Revenue Increase – Including Energy Efficiency			
	Rate Year 1 ($000,000)	Rate Year 2 ($000,000)	Rate Year 3 ($000,000)
Electric	19.725	18.581	25.083
Gas	6.654	6.702	8.183

C. Electric Bill Credits

To achieve rate moderation, electric bill credits of $6 million in Rate Year 1, $9 million in Rate Year 2 and $11 million in Rate Year 3 will be applied using available regulatory liabilities. The bill credit will be allocated to each service class in proportion to class responsibility for the overall delivery rate increase. The allocated credits will be refunded to customers on kilowatt-hour or kilowatt basis through the existing Electric Bill Credit Mechanism.

D. Gas Bill Credits

To achieve rate moderation, in a manner similar to the electric bill credits, gas bill credits of $2.5 million in Rate Year 1, $3 million in Rate Year 2 and $3 million in Rate Year 3 will be applied using available regulatory liabilities. The bill credit will be allocated to each service class in proportion to class responsibility for the overall delivery rate increase. The allocated credits will be refunded to customers on a Ccf basis through the existing Gas Bill Credit Mechanism which is applicable to firm Service Classifications ("SCs") 1, 2, 6, 11 – DLM, 11 – D, 11 – T, 12 and 13.

For billing purposes, any applicable credit up to $1 million resulting from SC 11 gas delivery service to the Danskammer Generating Station ("Danskammer"), as described in Section IX.A herein, will be included in the Gas Bill Credit, with the combined amount shown as one line item on customer bills.

E. Delivery Revenue Increases After Moderation

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

Delivery Revenue Increase After Moderation			
	Rate Year 1	Rate Year 2	Rate Year 3
Electric	$13.725 million[9] ($19.725 million Rate Year 1 increase, minus $6.0 million bill credit)	$15.581 million (expiration of $6.0 million Rate Year 1 credit plus $18.581 million Rate Year 2 increase, minus $9.0 million bill credit)	$23.083 million (expiration of $9.0 million Rate Year 2 credit plus $25.083 Rate Year 3 increase, minus $11.0 million bill credit)
Gas	$3.154 million[10] ($6.654 million Rate Year 1 increase, minus $3.5 million bill credit)	$6.202 million (expiration of $3.5 million Rate Year 1 credit plus $6.702 million Rate Year 2 increase, minus $4.0 million bill credit)	$8.183 million (expiration of $4.0 million Rate Year 1 credit plus $8.183 million Rate Year 3 increase, minus $4.0 million bill credit)

F. Make Whole Provision

To the extent Commission approval of this Proposal occurs after July 1, 2018, Central Hudson will recover the revenue shortfall resulting from the extension of the suspension period through a make whole provision. The make whole provision is designed to ensure that, by June 30, 2019, Central Hudson is restored to the same financial position had new delivery rates gone into effect on July 1, 2018.

The Company will calculate any revenue adjustments as the difference between: (1) sales revenues the Company would have billed at new rates during the extension of

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9 See Cases 14-E-0318 et al., Joint Proposal at 7 (Apr. 22, 2015) ("2015 Central Hudson JP"). This delivery revenue increase does not reflect the expiration of the $2.0 million Rate Year credit for Rate Year 3 (July 1, 2017 – June 30, 2018) resulting from the 2015 Central Hudson JP.

10 Reflects 50% of Danskammer revenues refunded through bill credit as described in Section III.D of the 2015 Central Hudson JP and a $400,000 decrease in interruptible revenues imputed in base rates. This delivery revenue increase does not reflect the expiration of the $1.493 million Rate Year credit for Rate Year 3 (July 1, 2017 – June 30, 2018) resulting from the 2015 Central Hudson JP.

the suspension period beginning July 1, 2018; and (2) the same level of sales revenues for the concurrent period at current rates. The revenue adjustments would include all applicable surcharges and carrying charges and would be subject to reconciliation in accordance with all applicable adjustment mechanisms and will be collected over the remainder of Rate Year 1 measured from the date new rates are billed. The make whole will be recovered through the existing Miscellaneous rate component for electric and the new gas surcharge as described in Section XII.K. An example is set forth in Appendix B.

V. ACCOUNTING MATTERS

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

1. Components of Net Plant

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

2. Electric and Gas Net Plant Targets

The electric and gas revenue requirements for Rate Year 1, Rate Year 2, and Rate Year 3 are based on the net plant and depreciation expense targets set forth in Appendix C. These targets are applicable only to the time periods specified and not any subsequent period, notwithstanding any other provision of this JP. The actual average electric and gas net plant balances and depreciation expense at the end of each Rate Year will be calculated using the calculation methods described in Appendix D.

3. Net Plant Target Reconciliations

The actual electric and gas net plant and depreciation expense will be reconciled to the combined electric and gas net plant and depreciation expense targets for Rate Year 1, Rate Year 2, and Rate Year 3 on an annual Rate Year basis. The revenue requirement impact (i.e., return and depreciation as described in Appendix D) resulting from the total difference (whether positive or negative) in actual average net plant balances and depreciation expense and the combined target levels will carry forward for each of the Rate Years and will be summed algebraically at the end of Rate Year 3.

4. Deferral for the Benefit of Ratepayers

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

5. Existing Reporting

The Company will continue to provide Staff by March 1 of each year a report on its capital expenditures during the prior calendar year using a format similar to that presented in Appendix E to this JP. In addition, the Company will continue to file its five-year capital investment plan with the Secretary to the Commission ("Secretary") annually by July 1. The annual report will include an explanation of any cost variance between the approved budget and an actual expenditure greater than 10% for any single project identified in the Company's Major Capital Project Report shown in Appendix E, Sheet 1. The three-year capital investment plan agreed to in this Proposal is set forth in Appendix Y.

6. New Reporting

a) Capital Expenditures Variance Reporting

The Company will file with the Secretary quarterly capital variance reports within 45 days of the end of each quarter using a format similar to that presented in Appendix E, Sheet 2. In lieu of a report for the fourth quarter, the Company will submit an annual report within 60 days of the end of the calendar year.

b) Capital Information Technology Reporting

The Company will file a detailed annual report that identifies the planned information technology ("IT") projects for the following calendar year by November 1, including a prioritized project list and estimated costs. This report will include: (1) the final variance summary of all on-going and active capital projects and programs; (2) an explanation of any cost or timeline exceeding 10% of forecast; (3) a narrative on changes to any IT project design, contracts, or software; (4) a description of benefits of any new IT projects or programs; and (5) any quantitative benefit/cost analysis to date and/or forecast, including the methodology used.

Beginning with the quarter ending March 31, 2019, the Company will file with the Secretary quarterly reports that will include: (1) any changes to the IT project prioritization with an explanation; (2) the expense variance by project; and (3) an explanation for any cost variance exceeding 10% of the approved budget.

These and other new reporting requirements are listed in Appendix P.

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

B. Deferral Accounting

1. Continuing Deferrals

Except as expressly modified within this JP, the Company is authorized to continue its use of all continuing accounting deferrals for revenues, expenses and costs as specified in the 2015 Rate Plan applicable in Rate Year 3 of that rate plan or for which Commission authorization for deferral accounting is currently effective whether by reason of a Commission order, policy of general applicability, or a Commission determination with specific reference to the Company.

Without limiting the foregoing, the accounting deferrals applicable in Rate Year 3 from the 2015 Rate Plan include the following expenses and costs that will continue without modification:

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

b) Deferred Temporary Metro Transit Bus Tax Surcharge;

c) FAS 109;

d) Interest Costs on New Issuances of Long-Term Debt for Rate Years 2 and 3;

To account for current uncertainty in regard to the forecasted long-term debt cost rate, in particular due to the relatively large amount of new debt being forecasted by Central Hudson, the Rate Year 2 and Rate Year 3 actual embedded average cost rates of long-term debt (fixed or variable rate debt) will be reconciled to the 4.30% forecasted average cost rate of long-term debt used in determining the rates of return for Rate Years 2 and 3 shown in Appendix J, Schedule 2. At the end of each Rate Year, the difference between the actual embedded average cost rates of long-term debt and the 4.30% forecasted average cost rate of long-term debt will be multiplied by the respective forecasted electric and gas rate base amounts illustrated in Appendix A and the forecasted long-term debt ratio percentages illustrated in Appendix J, Schedule 1. This will result in the forecasted amount of long-term debt for each department (electric and gas), in each of Rate Year 2 and 3, being multiplied by the change in the average cost rates of long-term debt relative to 4.3%. The amounts so measured will be deferred for future recovery, or returned to customers, with carrying charges at the PTROR;

e) Interests Costs on Existing Variable Rate Debt;

In all three Rate Years, the actual interest rate of existing variable rate debt, consisting of the 1999 New York State Energy Research and Development Authority ("NYSERDA") Series B issuance or its successor and the 2014 Series E or its successor, will be reconciled to the interest rates shown in Appendix J, Schedule 2 and the difference will be reflected in the updated average cost of long-term debt and the updated weighted average cost of debt for the respective Rate Year. In the event the

1999 NYSERDA Series B issuance or its successor and the 2014 Series E or its successor are refinanced, the Company is permitted to defer and amortize the costs associated with its new debt, subject to conditions in any financing order issued by the Commission;

f) Commission Initiated or Required Management and Operation Audit Costs;

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

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

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

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

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

l) Property Taxes;

The deferral set forth in the 2015 Rate Plan for property taxes during Rate Year 3 of that rate plan will continue. For each Rate Year, the difference between the rate allowance for property tax expense (including school, county, city, town, and village) and actual property tax expense on a Rate Year basis will be deferred for future recovery, or returned to customers, with carrying charges at the PTROR. Differences will be shared 90/10 between customers and the Company, respectively; provided, however, that the Company's pre-tax loss or gain will be limited to five basis points ("BP") per (electric and gas) department for each Rate Year;

m) Commodity-Related Deferrals (Purchased Electric Costs and Purchased Gas Costs);

The Company is authorized to continue its current deferral practices incident to commodity/delivery mechanisms, such as Energy Cost Adjustment Mechanism, Gas Cost Adjustment, etc., which recognize the timing differences that occur between the actual purchases of energy requirements and the collection of costs from customers;

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

o) Gas Revenue Decoupling Mechanism (“RDM”);

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

q) Stray Voltage – Testing and Mitigation Costs;

r) Asset Retirement Obligation Deprecation and Accretion Expense;

s) Major Storm Reserve as described in Appendix U; and

t) Reforming the Energy Vision (“REV”) Demonstration Projects;

The Company may defer the revenue requirement effect of REV demonstration projects up to 0.5% of the delivery service revenue requirement, or the revenue requirement associated with capital expenditures of $10 million, whichever is larger.

2. Modified Deferrals

The following deferrals from the 2015 Rate Plan are modified:

a) Deferred Unbilled Revenues

As required by the Order Approving Accounting Change with Modification issued on July 20, 2016 in Cases 14-E-0318 and 14-G-0319, the Company has deferred $5.1 million of unbilled revenues to PSC Account 254.32.[11]

b) Deferred Vacation Pay Accrual

The Company is now authorized to defer vacation pay, adjusted quarterly for the current accrual instead of annually.

c) Earnings Sharing Mechanism

The Earnings Sharing Mechanism has been modified as set forth in Section VII herein.

d) Economic Development

The Company is authorized to record Economic Development expenditures against the existing deferred balance. In addition, if the deferred account balance is exhausted, the Company is now authorized to defer Economic Development expenditures for future recovery from customers.

e) Low Income Program

Consistent with the Order Approving Implementation Plans with Modifications issued on February 17, 2017 in Case 14-M-0565 ("Low Income Order"),[12] the following

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[11] Cases 14-E-0318 et al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Order Approving Accounting Change with Modification (July 20, 2016).

deferrals are authorized. The Low Income Program discounts are more fully described in Section XI:

i. Low Income Bill Discount Program

The Company is authorized to defer Low Income Bill Discount Program costs in excess of the amount set forth in this JP for future recovery from customers pursuant to the Low Income Order. Any under-expenditures will be deferred for future use to support low income programs.

ii. Low Income Arrears Forgiveness

Consistent with the Low Income Order, the arrears forgiveness program will be continued and phased out during Rate Year 2 (April 2020). Symmetrical deferral is authorized for the differences compared to amounts established in rates.

iii. Low Income Waiver of Reconnection Fee

Central Hudson is authorized to continue to provide the Reconnection Fee Waiver program under the Low Income Program. Symmetrical deferral is authorized for the differences compared to amounts established in rates.

f) Governmental, Legislative and Other Regulatory Actions

The Company is authorized to defer the revenue requirement effect of new legislative, governmental, Commission or other regulatory or legislative actions subsequent to the execution hereof that in the aggregate in a Rate Year have material consequences (ten BPs or more of return on common equity for either the gas

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[12] Case 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers, Order Approving Implementation Plans with Modifications (Feb. 17, 2017).

department or the electric department) for any elements of cost, with carrying charges at the PTROR.

g) Electric RDM

The electric RDM will continue to be applicable to SCs 1, 2, and 6 and those customers taking service under SC 14 whose parent service classification would be SC 1, 2 or 6. The RDM is expanded to include SCs 3, 5 and 8. The Geothermal Rate Impact Credit will be funded through an expense component of the electric RDM as set forth in Section XII.F herein.

h) Right of Way Maintenance Tree Trimming Costs – Transmission and Distribution

There will now be an annual reconciliation for Central Hudson's distribution and transmission vegetation management programs. The true-up provides the Company the flexibility of allowing specified dollar amounts to be moved between Rate Years. The vegetation management program true-ups, which will apply to each program separately, are described below.

i. Distribution Vegetation Program

1. Rate Year 1

The Company may defer funds from under-spending the Rate Year 1 allowance by an amount less than or equal to $1 million for use in Rate Year 2. If the Company underspends by an amount greater than $1 million, the Company may defer $1 million for use in Rate Year 2 and the remaining underspend will be deferred for ratepayer benefit. To provide flexibility, the Company may overspend the Rate Year 1 allowance by an amount less than or equal to $1 million, and defer the overspend to Rate Year 2, thereby reducing the Company's Rate Year 2 allowance.

2. Rate Year 2

The Company may defer funds from under-spending the Rate Year 2 allowance and any dollars deferred from Rate Year 1 by an amount less than or equal to $1 million for use in Rate Year 3. If the Company underspends by an amount greater than $1 million, the Company may defer $1 million for use in Rate Year 3 and the remaining underspend will be deferred for ratepayer benefit. To provide flexibility, the Company may overspend the Rate Year 2 allowance and any dollars deferred from Rate Year 1 by an amount less than or equal to $1 million, and defer the overspend to Rate Year 3, thereby reducing the Company's Rate Year 3 allowance.

3. Rate Year 3

If the Company underspends the Rate Year 3 allowance and any dollars deferred from Rate Year 2, all of the underspent dollars will be deferred for ratepayer benefit. If the Company overspends the Rate Year 3 allowance and any dollars deferred from Rate Year 2, all of the overspent dollars will be absorbed by the Company. There will be no deferral of funding past Rate Year 3. An example is set forth in Appendix F, Schedule 3.

For the avoidance of doubt, any over- or under-spend in Rate Year 1 and Rate Year 2 is authorized for accounting deferral treatment to the subsequent period. In Rate Year 3 any under-spend is authorized for accounting deferral treatment to the subsequent period. Carrying charges at the PTROR will be applied by the Company to the amount deferred from the end of Rate Year 3 until the effective date of the

Company’s next rate order. Carrying charges will not apply during Rate Year 1 and Rate Year 2.

ii. Transmission Vegetation Program

1. Rate Year 1

The Company may defer funds from under-spending the Rate Year 1 allowance by an amount less than or equal to $500,000 for use in Rate Year 2. If the Company underspends by an amount greater than $500,000, the Company may defer $500,000 for use in Rate Year 2 and the remaining underspend will be deferred for ratepayer benefit. To provide flexibility, the Company may overspend the Rate Year 1 allowance by an amount less than or equal to $500,000, and defer the overspend to Rate Year 2, thereby reducing the Company’s Rate Year 2 allowance.

2. Rate Year 2

The Company may defer funds from underspending the Rate Year 2 allowance and any dollars deferred from Rate Year 1 by an amount less than or equal to $500,000 for use in Rate Year 3. If the Company underspends by an amount greater than $500,000, the Company may defer $500,000 for use in Rate Year 3 and the remaining underspend will be deferred for ratepayer benefit. To provide flexibility, the Company may overspend the Rate Year 2 allowance and any dollars deferred from Rate Year 1 by an amount less than or equal to $500,000, and defer the overspend to Rate Year 3, thereby reducing the Company’s Rate Year 3 allowance.

3. Rate Year 3

If the Company underspends the Rate Year 3 allowance and any dollars deferred from Rate Year 2, all of the underspent dollars will be deferred for ratepayer benefit. If the Company overspends the Rate Year 3 allowance and any dollars deferred from Rate Year 2, all of the overspent dollars will be absorbed by the Company. There will be no deferral of funding past Rate Year 3. An example is set forth in Appendix F, Schedule 3.

For the avoidance of doubt, any over- or under-spend in Rate Year 1 and Rate Year 2 is authorized for accounting deferral treatment to the subsequent period. In Rate Year 3 any under-spend is authorized for accounting deferral treatment to the subsequent period. Carrying charges at the PTROR will be applied by the Company to the amount deferred from the end of Rate Year 3 until the effective date of the Company's next rate order. Carrying charges will not apply during Rate Year 1 and Rate Year 2.

i) Danskammer Gas Revenues

This deferral is modified as set forth in Section IX.A herein.

j) External Rate Case Expense

The Company is now authorized to defer External Rate Case expenses incurred and amortize such costs over 36 months with no true-up mechanism.

k) Non-Wire Alternative Programs

The Company is authorized to defer the revenue requirement and associated incentives of its current Non-Wire Alternative ("NWA") Program as authorized by the Order Implementing with Modification the Proposal for Cost Recovery and Incentive Mechanism for Non-Wire Alternative Project issued on July 15, 2016 in Case

14-E-0318.[13] The Company is authorized to defer the revenue requirement and associated incentives of future NWA Projects implemented following the Commission's issuance of a final order in these proceedings. To the extent the Company implements a NWA that results in the displacement of a capital project reflected in the average electric net utility plant, the balance(s) will be reduced to exclude the forecast net plant associated with the displaced project. The carrying charge, or a portion thereof as warranted, on the reduction of the average electric net utility plant that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NWA.

l) Gas Leak Prone Pipe ("LPP") – Miles Above Target

The Company is authorized to defer a 2 BP positive revenue adjustment ("PRA") for each mile of LPP the Company replaces or eliminates in excess of the 15-mile LPP target, capped at a maximum of 6 miles (or 12 BPs) on a calendar year-end basis.

m) Gas LPP – Cost Per Mile

The Company is authorized to defer the revenue requirement effect (i.e., depreciation and return on investment) premised on capital expenditures capped at the following amounts per mile for each mile completed above the annual target of 15 miles as set forth in Section XVII.E: (1) 2018 - \$1.780 million; (2) 2019 - \$1.895 million; (3) 2020 - \$2.010 million; and (4) 2021 - \$2.125 million.

[13] Case 14-E-0318, Order Implementing with Modification the Proposal for Cost Recovery and Incentive Mechanism for Non-Wire Alternative Project (July 15, 2016).

3. Expiring Deferrals

The accounting deferrals from the 2015 Rate Plan for the following revenues, expenses and costs will expire:

a) Competition Education Program;

b) Competitive Metering Initiative;

c) International Financial Reporting Standards;

d) Empire Zone Rate Lost Revenues;

e) Nine Mile Point 2 - NEIL insurance credits and associated costs;

f) PSC General Assessment;

g) NYS Temporary 18-a Surcharge (phased out pursuant to Order Approving Temporary State Assessment Tariff Amendments issued on December 19, 2017 in Case 09-M-0311);[14]

h) RPS, EEPS and SBC – now covered under Clean Energy Fund;

i) Energy Efficiency Incentives (EEPS1 and EEPS2);

j) Security of Infrastructure;

k) NYS Income Taxes – Non-Income Based Tax;

l) Revenue Requirement Effect of Bonus Depreciation;

m) Revenue Requirement Effect of Interconnection Portal and Hosting Capacity Analysis; and

n) Revenue Requirement Effect of actual Federal Tax Research Credit compared to amounts assumed in tax calculation.

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[14] Case 09-M-0311, Implementation of Chapter 59 of the Laws of 2009 Establishing a Temporary Annual Assessment Pursuant to PSL 18-a(6), Order Approving Temporary State Assessment Tariff Amendments (Dec. 19, 2017).

4. New Deferrals

The following new deferrals are added:

a) Electric and Gas Energy Efficiency

For the period beginning July 1, 2018 through December 31, 2021, actual Energy Efficiency Transition Implementation Plan ("ETIP") expenses, for which recovery was moved to base rates effective July 1, 2018, will be compared to the cumulative rate allowance shown on Appendix A, Schedule 1 (Electric) and Schedule 2 (Gas) of this Proposal for the period July 1, 2018 through June 30, 2021, plus an amount equal to half of the rate allowance for Rate Year 3 for the period July 1, 2021 through December 31, 2021. During this period, the Company will be allowed to defer any over/under expenditures. At December 31, 2021, any net cumulative under-expenditures will be deferred to be utilized by the Company to reduce the revenue requirement associated with future energy efficiency programs. In the event that the Company spends in excess of the allowance over the cumulative period, the Company will absorb the earnings impact of the over-expenditure. Actual expenditures shall include any funds set aside for customers enrolled in self-direct programs. Specifically, regarding the electric deferral, the determination of this deferral should be calculated by comparing actual expenditures to the rate allowance less any funding reallocated to the Carbon Reduction Program ("CRP") which is capped at $4,526,879[15] over this period.

[15] ($1,293,394 x 3) + ($1,293,394 x ½) = $4,526,879. The $1,293,394 reflects a 15% increase in electric energy efficiency funding.

Carrying charges at the PTROR will be applied by the Company to the amount deferred from the end of December 2021 until the effective date of the Company's next rate order. Carrying charges do not apply prior to December 2021.

b) Carbon Reduction Program

For the period beginning July 1, 2018 through December 31, 2021, actual CRP expenses will be compared to the cumulative rate allowance shown on Appendix A, Schedule 1 (Electric) for the period July 1, 2018 through June 30, 2021, plus an amount equal to half of the rate allowance for Rate Year 3, or a total of $1,225,000.[16] During this period, the Company will be allowed to defer any over/under expenditures. At December 31, 2021, any net cumulative under-expenditures will be deferred and retained by the Company to reduce the revenue requirement associated with future CRP initiatives. In the event that the Company spends in excess of the allowance over the cumulative period, the Company will absorb the earnings impact of the over-expenditure. Should the Company reallocate funding from the Energy Efficiency Program to the CRP, actual expenditures will be compared to an amount equaling the designated rate allowance plus the reallocated funds. The Company is permitted to reallocate up to $4,526,879[17] from the electric Energy Efficiency Program to the CRP over the cumulative period.

Carrying charges at the PTROR will be applied by the Company to the amount deferred from the end of December 2021 until the effective date of the Company's next rate order. Carrying charges do not apply prior to December 2021.

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16 ($350,000 x 3) + ($350,000 x ½) = $1,225,000.

17 See Footnote 15 supra.

c) Tax Cuts and Jobs Act of 2017

The Company will be held harmless for any changes it is required to make due to the Tax Cuts and Jobs Act of 2017 ("Tax Reform Act") and/or any state or local action resulting from the Tax Reform Act and is authorized to defer the revenue requirement of any changes it is required to make due to the Tax Reform Act.

Further, the Signatories recognize that the Commission is addressing the changes in the federal tax law in Case 17-M-0815, Proceeding on Motion of the Commission on Changes in Law that May Affect Rates, which may necessitate that the Company take additional actions or cause the Company to become eligible for additional benefits, and the Signatories recognize that this could result in changes to the treatment of federal taxes, or the ratemaking effects of these federal tax changes, that are different from those set forth in this Proposal.

d) Revenue Requirement Effect of Cloud-Based or Software as a Service ("Saas") Solutions

The Company is authorized to defer the revenue requirement effect of variations resulting from software solutions chosen that require a different accounting treatment under FASB standards compared to amounts assumed in the establishment of net plant and depreciation expense. The deferral resulting from each project will not be in excess to the individual initial project costs included in rates. This deferral will be offset by the revenue requirement effect (i.e., return on and depreciation) of the actual project cost which will be adjusted out of the established net plant targets as described in Appendices C and D. An example is set forth in Appendix F, Schedule 2.

In the event that a deferral is recorded, the Company will file a notice with the Secretary that identifies the project (with reference to the required reporting of the IT capital project under Section V.A.6 herein) and calculates the deferral, including adjustments from the net plant targets. This notice will be in lieu of a deferral petition and would not be subject to the Commission's traditional three-part deferral test.

e) Credit/Debit Card Fees and Walk-In Center Fees

The Company is authorized to defer costs over/under the rate allowance for costs associated with Credit/Debit Card Fees, including Walk-In Center transaction fees and outreach and education related to the credit card program.

f) Type 3 Leak Repair Incentive

The Company is authorized to defer the PRA associated with the Type 3 Leak Repair Incentive as described in Section XVII.B.2 herein.

g) Training Center and Primary Control Center Costs

The Company is authorized to defer for future recovery the incremental revenue requirement effect of capital and operating expenses as described under Training Center reporting in Section XV herein.

h) Incremental Costs Associated with Case 14-M-0101

The Company is authorized to defer the incremental revenue requirement effect of capital expenditures or operating expenses associated with the Case 14-M-0101, <u>Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision</u> ("REV Proceeding") REV Proceeding and related proceedings and Commission orders that are over/under the rate allowance for such costs included in the revenue requirements as a component of Consulting & Professional services.

i) Platform Service Revenues from CenHub

The Company will defer 80% of the Company's share of the revenue earned from sales through the CenHub platform for the benefit of customers.

j) Revenue Requirement Effect of Energy Storage Projects

During the term of this Rate Plan, Central Hudson is authorized to defer the incremental revenue requirement effect of up to two energy storage projects to comply with the Commission's directive in its March 9, 2017 Order on Distributed System Implementation Plan Filings in Case 16-M-0411.[18] For each energy storage project(s), Central Hudson will file: (1) an implementation plan, to be updated annually or more frequently as necessary; (2) notice with the Secretary, including the calculated change in revenue requirement associated with the energy storage project(s); and (3) quarterly reports detailing expenditures during the quarter, total expenditures to date, initially forecasted project budget, current forecast budget (if different than initially forecasted), an in-service date forecast and project activities and progress during the quarter. The implementation plan and notice to the Secretary will be in lieu of a deferral petition and will not be subject to the Commission's traditional three-part deferral test. The method of recovery of any deferred amounts will be addressed in Central Hudson's next rate case. Central Hudson will engage with Staff to discuss its planned project(s) prior to filing the implementation plan and notice with the Secretary.

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[18] Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Order on Distributed System Implementation Plans (Mar. 9, 2017).

k) Non-Pipe Alternative Deferral

Central Hudson is authorized to defer the revenue requirement effect of development and implementation of Non-Pipe Alternative ("NPA") projects. Specifically, Central Hudson will maintain appropriate accounting to adjust net plant targets by removing the effect of the capital project not implemented. To the extent the Company implements a NPA that results in the displacement of a capital project reflected in the average gas net utility plant, the balance(s) will be reduced to exclude the forecast net plant associated with the displaced project. The carrying charge, or a portion thereof, as warranted, on the reduction of the average gas net utility plant that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NPA.

l) Pension and OPEB Reserve Carrying Charges

The Company is authorized to accrue 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.

m) Federal Emergency Management Agency Grant Microgrid Project Funds

The Company is authorized to defer the revenue requirement effect of the Company's contributory funds and funds not reimbursed for Phase 1 and Phase 2, if approved by the Federal Emergency Management Agency, of the Hazard Mitigation Grant Program Project # 4085-0090 microgrid project.

n) Directors Fees

The Directors Fees, included in the Miscellaneous General element of expense, will be subject to deferral if Management Audit Recommendations 4.3 and 4.4 are implemented as recommended by Overland Consulting in Case 16-M-0001, In the Matter of a Comprehensive Management and Operations Audit of Central Hudson Gas & Electric Corporation.

o) Residential Methane Detection Program and First Responder Training

In the event the fund balance of the existing Gas Negative Revenue Adjustment ("NRA") deferred balance (PSC Account 254.37) is exhausted through funding the Residential Methane Detection Program and First Responder Training Program as described in Sections XX.F and XX.G, the Company is authorized to defer expenditures in excess of this funding for future recovery from customers.

p) Energy Efficiency Exemptions

The Company is authorized to defer differences between electric Energy Efficiency exemptions imputed in base rates and actual Energy Efficiency exemptions as described in Section XIII.

C. Listing of Deferrals

A summary listing of deferrals and applicable examples is set forth in Appendix F, together with the specific deferral method and associated carrying charge for each. While this listing is intended to be comprehensive, the Signatories recognize that other deferral accounting employed by the Company may have inadvertently been excluded. Accordingly, the list is without prejudice with respect to any error or omission and each

Signatory reserves the right to revise this listing pursuant to the procedures set forth in Section XXV of this JP.

D. Deferral Extension/Continuation

For the avoidance of doubt, the deferrals authorized or permitted consistent with this JP will not terminate by reason of the end of Rate Year 3, but shall continue until such time as they are superseded or expressly revoked.

E. Right to Petition

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

F. Projected Net Deferred Regulatory Credits

Actual July 1, 2018 balances for the items shown on Appendix H will be offset against each other as of July 1, 2018, with the net deferred credit balance available for rate moderation. Any unused balance shall remain deferred, with carrying charges at the PTROR.

G. Revenue Matched Rate Allowances

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

H. Fortis Overhead Allocation Methodology

Subject to the cost allocation requirements set forth in the Order Authorizing Acquisition Subject to Conditions issued on June 26, 2013 in Case 12-M-0192 ("Acquisition Order"),[19] the Company will report any changes in the allocation methodology of Fortis overhead costs within 60 days after the revised cost allocation effective date. The Company will also report any change in the Fortis Overhead Allocation Methodology in its Annual Report of Affiliate Transactions filed on April 1 of each year pursuant to the Acquisition Order.

I. Depreciation

1. Depreciation Expense

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

2. Gas Iroquois Transmission

Currently, the Accumulated Depreciation Reserve is in excess of the Plant in Service balance for certain Gas Iroquois Transmission accounts, such as Structures & Improvements and Station Equipment. Separate Depreciation Reserve Accounts are established to recognize the depreciation expense being collected to recover the cost of the asset over its service life and the cost to remove the asset from service upon retirement. As it relates to the portion of the Depreciation Reserve related to the life of

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

the asset, the Accumulated Depreciation Book Reserve should not be greater than the Plant in Service balance in any of the individual accounts. Accumulated Depreciation in excess of the Plant in Service balances related to the cost to remove the asset from service will be tracked separately. The Company will be allowed to continue collecting associated Cost of Removal.

VI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure and Return on Equity

The common equity ratio is 48% for Rate Year 1, 49% for Rate Year 2 and 50% for Rate Year 3. The capital structures and cost rates for debt and customer deposits are shown by Rate Year in Appendix J. The allowed return on common equity ("ROE") is 8.80% for all three Rate Years. The Signatories support this provision to recognize the importance of maintaining the Company's and Commission's stated support for Central Hudson to maintain an "A" credit rating as set forth at page 13 of the Acquisition Order. The Signatories also acknowledge the change in creditworthiness associated with the Tax Reform Act and recognize that conditions or Commission policies may change in the future. Nothing herein is precedent for the equity ratio to remain at the Rate Year 3 level of 50% in future rate cases. The equity ratio will be reconsidered to reflect Central Hudson's then-current financial circumstances.

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

The average cost of long-term debt is 4.3% for all three Rate Years with deferral in Rate Year 2 and Rate Year 3 as described in Section V.B.1. The Customer Deposit Rate is 1.05% for all three Rate Years.

VII. EARNINGS SHARING MECHANISM

A. Thresholds

The allowed ROE established for the term of the JP is 8.80%. Actual regulatory earnings in excess of 8.80% and up to 9.30% are authorized and will be retained by the Company. Earnings in excess of a 9.30% ROE and up to a 9.80% ROE will be shared equally between customers and shareholders. Actual regulatory earnings in excess of a 9.80% ROE and up to a 10.3% ROE will be shared 80/20 (customer/shareholder). Actual regulatory earnings in excess of a 10.30% ROE will be shared 90/10 (customer/shareholder). These regulatory earnings sharing percentages shall be maintained until the effective date of the Company's next rate order.

B. Reporting and Calculation of Actual Regulatory Earnings

The Company will file a report with the Secretary within 90 days following the end of each Rate Year showing a computation of its actual regulatory earnings for the preceding Rate Year. The Company's achieved regulatory return on common equity computation will be measured by (electric and gas) department and will reflect the lesser of an equity ratio equal to 50% or Central Hudson's actual average common equity ratio. The financial consequences of any regulatory performance mechanisms, positive or negative, including from Earnings Adjustment Mechanisms ("EAMs") and other ratemaking exclusions consistent with existing practices, will be excluded from the computations of actual regulatory earnings.

VIII. NEW AND MODIFIED REPORTING REQUIREMENTS

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

IX. FORECASTS OF SALES AND CUSTOMERS

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

A. Treatment of Danskammer Revenues

SC 11 gas delivery revenues from Danskammer will not be imputed in the base delivery revenue utilized to determine the base delivery revenue increases. To the extent that Danskammer has not provided notice of termination of SC 11 service pursuant to its SC 11 agreement, the SC 11 delivery revenue estimated to be received from Danskammer during each Rate Year will be estimated on the then-effective Maximum Daily Quantity ("MDQ") and applicable approved rates. Up to the first $1 million of Danskammer SC 11 gas delivery revenue per Rate Year will be applied as a rate moderator through gas bill credits. For the avoidance of doubt, if less than $1.0 million in SC 11 revenues are collected from Danskammer in a Rate Year, the bill credit will be adjusted downward accordingly.

The credit applicable will be determined by allocating the estimated revenue set forth above to SCs 1 and 12 combined, SCs 2, 6 and 13 combined, and SC 11 excluding Electric Generators ("EG") in proportion to each group's contribution to overall gas delivery revenues. The allocated credits will be divided by the forecasted deliveries of each service class group to determine the annual uniform Ccf rate within each service class group to be applicable during the Rate Year. For billing purposes, any credit to be provided from Danskammer delivery revenue will be included in the Gas Bill Credit described in Section IV.D herein.

Any difference between the estimated amount of credits to be provided and the actual amount of credits provided in each Rate Year will be deferred. For the avoidance of doubt, carrying charges at the other customer capital rate will apply while Danskammer delivery revenues are credited to customers. Firm delivery revenues collected from Danskammer in excess of the estimated amount to be refunded per Rate Year will be deferred and will accrue carrying charges at the PTROR for future disposition subject to Commission approval. On a Rate Year basis, any over- or under-refunded amounts for the 11 months ending in May of each year will be included in the determination of the credit factors to be applicable for the subsequent Rate Year. Reconciliation amounts related to the remaining one month will be included in the next subsequent rates determination.

Should Danskammer cease to exist or cease to exist as a customer during a Rate Year, the Company will terminate the refund of the credit as soon as practicable, subject to a notification filing with the Commission. Any resulting over- or under-refunded amounts will be deferred, with applicable carrying charges at the PTROR, for future disposition subject to Commission approval.

X. REVENUE ALLOCATION AND RATE DESIGN

A. Revenue Allocation

1. Electric Revenue Allocation

The Signatories agree on the electric revenue allocation set forth in Appendix L.

2. Gas Revenue Allocation

The Signatories agree to the gas revenue allocation set forth in Appendix L.

B. Rate Design

1. Electric Rate Design

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

This agreement, which includes adjustments to the Company's proposed fixed/customer charge in these proceedings, does not represent the position of each Signatory, but is a compromise to effectuate this agreement. The Signatories agree and understand that the "fixed charge" / "customer charge" and other rate design(s) arrived at in this agreement are not intended to set statewide policy or take precedence over any subsequent Commission order applicable to Central Hudson regarding rate design inclusive of the customer charge, if or when such an order is issued.

2. Gas Rate Design

The Signatories agree to the gas rate design set forth in Appendix M.

This agreement, which includes adjustments to the Company's proposed fixed/customer charge in these proceedings, does not represent the position of each Signatory, but is a compromise to effectuate this agreement. The Signatories agree and understand that the "fixed charge" / "customer charge" and other rate design(s) arrived at in this agreement are not intended to set statewide policy or take precedence over any subsequent Commission order applicable to Central Hudson regarding rate design inclusive of the customer charge, if or when such an order is issued.

For SC 11, the Signatories agree to establish a three-part rate consisting of: (1) a monthly customer charge; (2) a volumetric charge applicable to all monthly volume in excess of 1,000 Ccf per month; and (3) a demand charge applicable to a customer's MDQ. The Signatories also agree to combine the three SC 11 transmission rates from the 2015 Rate Plan into one transmission rate and combine the two SC 11 distribution rates from the 2015 Rate Plan into one distribution rate while also maintaining a Distribution Large Mains ("DLM") rate. The volumetric rate will be set to recover approximately 15% of delivery revenue allocated to SC 11 with the remaining estimated revenue less the customer charge being recovered through the MDQ charge.

3. Customer Bill Impacts

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

XI. PROVISIONS FOR LOW INCOME CUSTOMERS

A. Low Income Bill Discount Program

Pursuant to the Low Income Order, bill discounts are authorized for Home Energy Assistance Program ("HEAP") recipients as set forth in the Low Income Order. The bill discount credits are set forth in the electric and gas tariffs.[20]

[20] Bill discounts may change based on the annual Low Income Plan the Company is required to file with analysis of customer bills.

The level of funding provided for the bill discount credits, subject to symmetrical deferral as described in Section V.B.2.e., is provided below.

Funding ($000)	Rate Year 1	Rate Year 2	Rate Year 3
Electric	$5,727	$7,325	$7,992
Gas	$2,885	$3,690	$4,026
Total	$8,612	$11,015	$12,018

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

B. Arrears Forgiveness

The Low Income Order authorized the continuation of an Arrears Forgiveness Program that will be phased out during Rate Year 2. The following allowances, subject to symmetrical deferral as described in Section V.B.2.e., have been authorized:

Funding ($000)	Rate Year 1	Rate Year 2	Rate Year 3
Electric	$114	$5	$0
Gas	$28	$1	$0
Total	$142	$6	$0

C. Reconnection Fee Waiver

The Low Income Order authorized the continuation of the waiver of Reconnection Fees. An allowance of $51,000 for each Rate Year (split 80/20 between electric and gas), subject to symmetrical deferral as described in Section V.B.2.e, has been established.

XII. TARIFF-RELATED MATTERS

A. Generally

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

B. Standby Rates

Storage batteries will be included in the definition for “designated technologies” under section 14.5 (“Standby Rates Billing Phase-In for Certain Technologies”) of the standby service tariff.

Combined Nitrous Oxides (“NOx”) emissions for designated technologies exempt from standby rates under section 14.5 should be reduced from 4.4 lbs/MWh to 1.6 lbs/MW under the standby service tariff for customers that complete a Coordinated Electric System Interconnection Review (“CESIR”) on or after July 1, 2018. All CESIRs completed before July 1, 2018 are grandfathered under 4.4 lbs/MWh. Eligibility criteria for designated technologies were approved in the Order Directing Modifications to Standby Service Tariffs issued in Cases 02-E-0551 et al. on January 23, 2004.[21]

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[21] Cases 02-E-0551 et al., Proceeding on Motion of the Commission as to Rochester Gas and Electric Corporation's Electric Tariff Filing to Establish a New Standby Service in Accordance with Commission Order issued October 26, 2001 in Case 99-E-1470, Order Directing Modifications to Standby Service Tariffs (Jan. 23, 2004).

C. Reconnection Charges

Reconnection Charges applicable to service restoration to the same customer at the same meter location within 12 months after discontinuance of service will be revised as follows:

	Rate Year 1	Rate Year 2	Rate Year 3
Normal Business Hours	$35	$50	$60
Normal Business Hours with Line Crew or Gas Mechanic Crew	$140	$180	$220
Other Hours	$70	$100	$120
Other Hours with Line Crew or Gas Mechanic Crew	$200	$260	$310

Where a customer receives both electric and gas service, the Reconnection Charge for only one service will apply in the event of simultaneous reconnection of both gas and electric service.

D. Electric Service Classifications 5 and 8

The rates under SC 5 and SC 8, Rate A for all LED fixtures will reflect a 20-year ASL. The ASL for LED and non-LED will be reviewed in the Company's next rate filing. Additionally, in the Company's next rate filing, the Company shall perform a study to examine the rates and charges for all Company owned street lighting fixtures that compares them to all the underlying costs incurred to replace the fixture, maintain the fixture, and deliver energy to each of these fixtures. The Company will propose rate design changes taking into account this study and possible bill impacts.

In addition, the SC 8 Rate C annual delivery charges will be specifically identified in the tariff.

E. Economic Development Funding

All Economic Development funding will be provided from the existing Economic Development fund balance and the Company is authorized to defer any expense over the fund balance. This Rate Plan will continue the Economic Development programs as set forth in the 2015 Rate Plan with the exception of the Main Street Revitalization program, which has been discontinued.

F. Electric RDM

The Electric RDM will continue to apply to SCs 1, 2, and 6 and those customers taking service under SC 14 whose parent service classification would be either SCs 1, 2 or 6. The RDM will be expanded to include SC 3, including those customers taking service under SC 14 whose parent service classification would be SC 3, as well as SCs 5 and 8. The RDM is not applicable to SCs 9 and 13.

The structure and provisions of the electric RDM will continue per the 2015 Rate Plan and will be expanded to apply to SCs 3, 5 and 8, as set forth above, with delivery revenue targets established by month for each service classification or sub-classification. To the extent a municipality taking service under SC 8 switches from Rate A (Company owned and maintained) or Rate B (customer owned/Company maintained) to Rate C (customer owned and maintained), monthly delivery revenue targets will be adjusted utilizing the fixture types/inventory transferred. Geothermal Rate Impact Credits paid to customers taking service under SCs 1 and 6 will be subtracted from Actual Delivery Revenue in the month that they are incurred prior to the monthly comparison of Actual Delivery Revenue to the Delivery Revenue Target.

Delivery revenue targets for the Rate Year ending June 30, 2021 will remain in effect until otherwise changed by the Commission. An example is set forth in Appendix O.

G. Gas RDM

The gas RDM will continue to be applicable to SCs 1, 2, 6, 12 and 13, with the structure and provisions continuing per the 2015 Rate Plan. Delivery revenue targets for the Rate Year ending June 30, 2021 will remain in effect until otherwise changed by the Commission. The RDM is not applicable to SCs 8, 9, 11, 14, 15 and 16.

H. Electric Factor of Adjustment

Consistent with the treatment in the Order Establishing Rate Plan issued on June 18, 2010 in Cases 09-E-0588 et al.[22] and as continued in the 2015 Rate Order, the factors of adjustment ("FOA") will be the most recent 36-month system average based on data available through May 2018 and will continue to be differentiated by service level according to the following service class groups:

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

(2) SCs 2 Primary Demand and 3;

(3) SC 13 Substation; and

(4) SC 13 Transmission.

I. Lost and Unaccounted For Gas and Factors of Adjustment

Consistent with the treatment in the 2015 Rate Order, the FOA will exclude line pack and conversion values, will be calculated as the five-year average for the 12 months ending August 31 of each year and will be updated to be applicable to the

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[22] 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 Electric Service, Order Establishing Rate Plan (June 18, 2010).

period from November 1 to October 31. Annual negative values when calculating the five-year average will be set to zero. Actual performance against the FOA will be determined utilizing a dead band of two standard deviations, limited to ±0.5%, with the minimum for the bottom of the dead band set at 1.0000.

J. Interruptible Imputation

The interruptible imputation structure as set forth in the 2015 Rate Plan will be continued subject to the following:

(1) The imputation will be set at $2.6 million for each Rate Year;

(2) The classes receiving the benefit of the imputation will be expanded to include SC 11 (with the exception of SC 11 Electric Generators);

(3) Ninety percent of actual annual excess or shortfall amounts, as compared to the imputation level, will be refunded or surcharged to customers taking service under SCs 1, 2, 6, 11, 12 and 13;

(4) Any such refund or surcharge amounts will be allocated to each service class in proportion to its contribution to overall annual gas delivery revenue for each Rate Year;

(5) Refund or surcharge factors will be developed for SCs 1, 2, 6, 12 and 13, combined, and for SC 11, by dividing any such allocated refund or surcharge amount by the forecasted deliveries of each group (SCs 1, 2, 6, 12 and 13 and SC 11) to create a uniform factor per Ccf by group;

(6) The refund or surcharge factor developed for the SC 1, 2, 6, 12 and 13 group will continue to be addressed through the Gas Cost Adjustment Mechanism; and

(7) The refund or surcharge factor developed for SC 11 will be addressed through a new gas surcharge/sur-credit rate to be combined with other new gas surcharges.

K. New Gas Surcharge

A new Gas Miscellaneous Charge mechanism and bill line item will be implemented to address the recovery and refund of new initiatives addressed herein, including interruptible refunds or surcharges applicable to SC 11 as described in Section XII.J herein, amounts addressed through the Gas Rate Adjustment Mechanism as described in Section XIV herein and gas EAM incentives as described in Section XXI herein.

L. Merchant Function Charge and Lost Revenue

The MFC cost methodology continued by the Commission in the 2015 Rate Order will continue. Additionally, the existing retail access migration-related lost revenue mechanism will continue for the electric department, in which 50% of retail access migration related lost revenue is collected through the Supply Charge component of the MFC, which is avoided by retail access customers, and 50% through the Transition Adjustment, which is paid for by all customers. Further, the electric MFC revenue will continue to be reconciled through the RDM.

The revised methodology approved by the Commission in the 2015 Rate Order which restructured the gas MFC Net Lost Revenue reconciliation process will continue. This process compares monthly actual billed MFC revenue, by MFC group, to the monthly MFC revenue targets for each Rate Year as set forth in Appendix O, with any monthly over or under billed MFC revenue deferred for refund to or recovery from full service customers. At the end of each Rate Year, any over or under recovery, including estimated interest over the refund or recovery period at the Commission's rate for other customer-provided capital, will be divided by estimated sales by MFC group over the refund or recovery period to develop a reconciliation factor to be effective for the 12 months beginning September 1. Any over or under recoveries of any such gas MFC reconciliations will be addressed in a subsequent reconciliation period. MFC Revenue

Targets for the Rate Year ending June 30, 2021 will remain in effect until otherwise changed by the Commission.

M. Conforming Tariffs

The electric and gas tariffs will be amended, as necessary, to conform to the provisions set forth in this JP. Delivery rates for electric standby service provided under SC 14 and gas distributed generation service under SCs 15 and 16, which are designed to follow the parent service classification rates/cost of service, as well as for the Excelsior Jobs Program, which follow the marginal cost of service, will be included in the conforming tariffs.

XIII. ENERGY EFFICIENCY PROGRAM COSTS

The Company's electric and gas ETIP costs will be recovered in base rates instead of the Energy Efficiency Tracker Surcharge portion of the SBC. The annual electric and gas ETIP costs included in base delivery rates are $9.8 million and $1.2 million, respectively. The electric allocation will be based on 87.3% Energy and 12.7% Coincident Peak demand. The gas allocation will reflect the residential (SCs 1 and 12) and non-residential (SCs 2, 6, 11 and 13) cost recovery responsibility split of 86.7% and 13.3%, respectively, currently applied to the ETIP amounts authorized for recovery in Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs through the SBC. Costs will be deferred as described in Section V.B.4 herein.

The Company's electric and gas Energy Efficiency Program costs will be recovered in base rates beginning in Rate Year 1. Energy Efficiency Program costs and targets are subject to change pursuant to Commission action in Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative ("Energy Efficiency Proceeding").

In the event that the Commission does not provide specific cost recovery directives for any modifications to such budgets, the Company is authorized to defer and recover any such changes approved by the Commission.

The Company will apply an appropriate credit to those customers that currently have exemptions from the Energy Efficiency Tracker Surcharge portion of the SBC, such that the credit will preserve the economic value of the exemptions that otherwise would be lost by shifting the recovery of electric and gas ETIP costs from the SBC to base rates. To the extent a service class is not included in the RDM and the actual value of such exemptions provided differs by $10,000 or more from the value imputed in base rates, as presented in Appendix M, Sheets 5 through 7, the entire difference will be deferred for future disposition subject to Commission approval.

The Company is authorized to reset the SBC coincident with the effective date of this Rate Plan to remove the Energy Efficiency Tracker Surcharge costs previously projected to be recovered through the SBC for the months July through December 2018.

XIV. RATE ADJUSTMENT MECHANISM

The Company will implement a Rate Adjustment Mechanism ("RAM") to refund or recover the net balance of RAM Eligible Deferrals and Carrying Charges, PRAs, unencumbered NRAs and Costs. For the avoidance of doubt, incentives associated with EAM achievement will not be collected through the RAM. All RAM Eligible Deferrals and Costs shall be the difference between actual costs and the amounts provided for in base rates. All RAM revenues and deferrals are subject to reconciliation. Details regarding RAM eligible costs and mechanics can be found in Appendix G.

The listing of balances shown in Appendix G for return to or collection from customers through the RAM during the term of this Proposal is intended to be comprehensive, but the Signatories recognize that future circumstances may create the authorization of new regulatory assets or liabilities. The carrying charges associated with any such new assets or liabilities may be balances eligible for inclusion in the RAM. Accordingly, the Company will include, as part of its RAM compliance filing, any such carrying charge balances for collection from or pass-back to customers through the RAM.

XV. TRAINING CENTER AND CONTROL CENTER PROJECTS

Within 30 days of the Commission's issuance of a final order in these proceedings, the Company will file an initial report ("Initial Report") with the Secretary containing the proposed Training Center and Control Center Projects' ("Projects") scope and a timeline of major performance milestones, which will include deadlines for functional capability and operation/integration of the Projects. The Initial Report will also set forth the Company's expected incremental capital expenditures and operating expenses that would be incurred if the Projects are not pursued.

Within 60 days of the filing of the Initial Report, Staff and the Company will meet and discuss the major performance milestones timeline. If mutual agreement regarding the milestones cannot be reached, either the Company or Staff may seek a ruling from the Commission regarding appropriate milestones.

The Company will file with the Secretary a major milestone performance report within 30 business days of a milestone completion date ("Milestone Report") which: (1) describes the Projects' compliance with the applicable milestone(s); (2) identifies the

Company's view of the Projects' direct customer benefit(s); and (3) describes both electric and gas business impacts. If necessary, a Milestone Report will also indicate potential and appropriate remedial action for a specific Project that has not fully met a particular milestone. The Company and Staff recognize that milestones may need to be adjusted as the deployment of technology and future Commission decisions evolve. If mutual agreement cannot be reached on revisions, either party may seek a ruling from the Commission.

Staff will present its review of the Milestone Reports to the Director of the Office of Electric, Gas and Water ("Director") for approval. The Director's approval of the continuation of the Projects shall be documented in a letter from the Director to the Company with a copy filed with the Secretary.

While the Director's approval letter is pending or until such time as the Company is notified in writing by the Director that it must alter or cease deployment of the Projects, the Company is authorized to continue the Projects' implementation and may continue to recover all prudently incurred and committed expenditures (e.g., material purchases and incremental internal and external labor). In the event that the Director or the Commission delays or cancels deployment and implementation of a Project, a deferral mechanism will be established to recover the incremental revenue requirement effect of the capital and operating expenses that the Company incurs as a result of the delay or cancellation of the deployment and implementation of the Training Center Project and/or the Control Center Project.

XVI. ELECTRIC RELIABILITY

The electric service annual metrics for System Average Interruption Frequency Index (“SAIFI”) will be set at the following targets: (1) 2018 - 1.38; (2) 2019 - 1.34; and (3) 2020 - 1.30.

The target for Customer Average Interruption Duration Index (“CAIDI”) will continue to be 2.50.

All electric reliability targets shall remain in effect until modified by a Commission order in a subsequent Central Hudson electric rate case. Electric Reliability Reporting requirements, quarterly meeting requirements, revenue adjustment source, and exclusions are defined in Appendix Q.

XVII. GAS SAFETY

The Signatories agree to the following Gas Safety Metrics beginning in calendar year 2018 as described below and identified in Appendix R. Emergency response performance and damage performance shall adhere to the reporting criteria for the annual Gas Safety Performance Measures report.

A. Emergency Response Time

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

Emergency Response Time	Percent Completed	(NRA)/PRA (BP)
30 Minute Response	≥ 90%	6
	≥85% - <90%	4
	≥80% - <85%	2
	≥75% - <80%	0
	< 75%	(9)
45 Minute Response	<90%	(6)
60 Minute Response	<95%	(3)

B. Leak Management

1. Gas Leak Backlog

The Gas Income Statement set forth in Appendix A, Schedule 2 include rate allowances for the Company's forecast of the number of gas leaks to be repaired and the costs per average repair. For purposes of determining the Total Year-End Backlog and Year-End Repairable Leaks Backlog, "Year-End" is defined as any time during the last 10 calendar days of the calendar year.

Should the Company fail to achieve the Gas Leak Backlog targets in any calendar year, starting in 2018, it will be subject to the (gas, pre-tax) NRAs listed below.

Gas Leak Backlog	# of Leaks	(NRA) (BP)
Total Year-End Backlog	100	(6)
Repairable Leaks Backlog	10	(12)

2. Type 3 Leak Reduction Incentive

Starting in 2018, the Company will be eligible to receive a PRA for repairing Type 3 leaks. If the Company eliminates 20 out of the 25 top prioritized Type 3 leaks, based on the Type 3 backlog as of January 1 each year, the Company will receive a PRA of four BPs.

Within 60 days of Central Hudson signing the Proposal, Central Hudson will file an initial report ranking the Type 3 leaks in the year-end 2017 backlog based on relative methane emissions. The ranking shall be based on the leak record. Central Hudson will earn the PRA if 20 of the top 25 leaks in that ranking have been eliminated by year-end 2018.

For the following years, Central Hudson will file an annual report by March 31 ranking the Type 3 leaks in the previous year-end backlog following the same methodology or improved methodology as proposed by the Company and agreed to by Staff. Central Hudson will earn the PRA if 20 of the 25 top leaks in that ranking have been eliminated by that year's end.

If the Type 3 year-end backlog for a previous year is less than 25, ranking is not necessary. Central Hudson will earn the PRA if the number of those leaks which have not been eliminated by that year's end is not more than five.

C. Excavation Damages

The gas Total Damage targets and corresponding potential NRAs are set forth below. The mismark targets, and Company/Company Contractor Damages targets have been eliminated. The Company has the option to use the two-year average performance if a target is missed in a given year.

	Calendar Year End (per 1000 tickets)				**(NRA)/PRA (BP)**
	2018	**2019**	**2020**	**2021**	
Total Damages	> 2.60	> 2.60	> 2.55	> 2.50	(27)
	>2.35 - ≤2.60	>2.35 - ≤2.60	>2.30 - ≤2.55	>2.25 - ≤2.50	(15)
	>2.10 - ≤2.35	>2.10 - ≤2.35	>2.05 - ≤2.30	>2.00 - ≤2.25	(5)
	>1.85 - ≤2.10	>1.85 - ≤2.10	>1.80 - ≤2.05	>1.75 - ≤2.00	0
	>1.60 - ≤1.85	>1.60 - ≤1.85	>1.55 - ≤1.80	>1.50 - ≤1.75	5
	≤ 1.60	≤ 1.60	≤ 1.55	≤ 1.50	10

D. Gas Safety Violations Performance Measures

Central Hudson will incur a NRA for instances of noncompliance (occurrences) of certain pipeline safety regulations set forth in 16 NYCRR Parts 255 and 261, as identified during Staff's annual field and record audits. Appendix S sets forth a list of identified High Risk and Other Risk pipeline safety regulations pertaining to this metric.

Central Hudson will be assessed a NRA for each High Risk or Other Risk occurrence, up to a combined maximum of 75 BPs on a calendar year basis, as follows:

High Risk Violation	Record Violations	BPs Per Occurrence	Field Violations	(NRA) BPs Per Occurrence
Per calendar year	1-5	0	1-20	(1/2)
	6-20	(1/2)	21+	(1)
	21+	(1)		

Other Risk Violation	Record Violations	BPs Per Occurrence	Field Violations	(NRA) BPs Per Occurrence
Per calendar year	1-15	0	All	(1/4)
	16+	(1/4)		

Record violations are capped at ten violations for each code requirement. For all violations over the cap, the Company must file an implementation plan to address such violation. Failure to adhere to the implementation plan will cause the Company to incur the full NRA.

A single missed step or requirement will only be counted once, as a specific section of code for the calculation of a NRA. The cumulative maximum exposure for record and field violations is 75 BPs in each calendar year. Repeated failure to follow a step or requirement that constitutes a violation will result in multiple occurrences of such violation. Failure to follow a Company procedure will be cited as a single occurrence under 16 NYCRR Part 255.603.

The Company is authorized to use code rule violation NRAs for First Responder Training and for the Residential Methane Detector Program as further described in Sections XX.F and XX.G.

The Company retains the ability to petition Staff for funding of other programs in the future which will enhance gas safety.

E. Leak Prone Pipe

Effective in 2018, the Company will replace or eliminate, at a minimum, 15 miles of LPP per year and will incur an NRA of 12 BP if the mileage achieved in any year is less than 15 miles. In the event the Company replaces or eliminates LPP in excess of 15 miles, the Company will earn a PRA of 2 BP per each additional mile, capped at a maximum of 12 BP per year.

The LPP cost per mile for planned projects includes reinforcement, upsizing, and non-LPP replacement. The allowed per-mile cost includes additional charges for New York State Department of Environmental Conservation spoils processing and is as follows: (1) $1.780 million per mile for 2018; (2) $1.895 million per mile for 2019; (3) $2.010 million per mile for 2020; and (4) $2.125 million per mile for 2021. The LPP deferral is capped at the foregoing annual per mile cost, which is calculated based on all planned projects inclusive of any reinforcement costs, replacement of existing section of non-LPP costs and service costs. This deferral is based on the revenue requirement effect (depreciation and return on investment at the PTROR) of the incremental capital expenditures. Based on the timing of when the incremental miles are typically completed, any deferral would be recognized and recorded on the books at the end of the calendar year in which the work was completed.

For the avoidance of doubt, not all pipe sections will be replaced in strict adherence to their risk ranking established by the Company's main segment risk model.

The Company expressly retains the right to prioritize projects based on factors other than risk.

F. Continuation

All Gas Safety Metrics effective in calendar year 2021 shall remain in effect on an annual basis for the target levels identified until modified by a Commission order.

XVIII. <u>CUSTOMER SERVICE</u>

A. Customer Service Quality Performance Mechanism

The Customer Service Quality Performance Mechanism and associated reporting requirements will consist of the following measures: PSC Annual Complaint Rate, the Customer Satisfaction Index, Residential Service Terminations/Uncollectibles Target, Call Answer Rate, and Appointments Kept measures. All Customer Service Quality Performance Mechanism targets and potential PRAs and NRAs shall remain in effect until modified by a Commission order. With the exception of the Residential Service Terminations/Uncollectibles metric, all metrics are measured on a calendar year basis starting in 2019. Residential Service Terminations/Uncollectibles are measured on a Rate Year basis. The Customer Service Quality Performance Mechanisms described below are summarized in Appendix T.

1. PSC Annual Complaint Rate

The criteria for the PSC Annual Complaint Rate and corresponding NRAs are:

PSC Annual Complaint Rate	(NRA)
<1.0	None
>=1.0 but <1.1	($300,000)
>=1.1 but <1.2	($600,000)
>=1.2 but < 1.3	($900,000)
≥1.3	($1,200,000)
Total Amount at Risk	**($1,200,000)**

2. Customer Satisfaction Survey

The criteria for the Customer Satisfaction Survey and corresponding potential NRAs are:

CSI Satisfaction Index	(NRA)
>=87%	None
<87% but >=86%	($300,000)
<86% but >=85%	($600,000)
<85% but >=84%	($900,000)
<84%	($1,200,000)
Total Amount at Risk	($1,200,000)

3. Residential Service Terminations/Uncollectibles Target

The Company is authorized to receive a positive incentive for reducing residential terminations for non-payment and residential uncollectibles as set forth below.

	Residential Terminations	Residential Uncollectibles
Five-Year Average	11,661	$5,115,077
Lower Target	7,500	$3,400,000
Positive Incentive (both measures at or below Lower Targets)	$925,000	
Positive Incentive (one measure at or below Lower Target, other is at or below Five-Year Average)	$462,500	

4. Call Answer Rate

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

The Call Answer Rate targets and corresponding NRAs are:

Call Answer Rate	(NRA)
>=60%	None
<60% but >=58%	($150,000)
<58% but >=56%	($300,000)
<56% but >=54%	($450,000)
<54%	($600,000)
Total Amount at Risk	**($600,000)**

5. Appointments Kept

The Company will continue to credit customers $20 per missed appointment.

B. Payment Options

1. Credit/Debit Card Payments

The Company will modify its existing credit/debit card bill payment option by permitting residential and non-residential customers to pay their Central Hudson bill by use of a credit or debit card without incurring a fee from a third-party agent processing such payments. The Company will not assess a convenience payment or other fee for use of a credit or debit card for payment on customers. The Company will defer the difference between actual expenditures, including outreach and education related to credit/debit card payments, over/under the rate allowance for credit and debit card fees as included in Appendix A.

The Company will issue a request for proposals ("RFP") from third-party vendors regarding the processing of credit/debit card payments. Within 90 days of the conclusion of the bidding process, the Company will file a report with the Secretary on the proposals and associated costs to the extent the Company is legally permitted to disclose such information.

The Company will file quarterly reports with the Secretary on associated costs. The quarterly reports will include administrative processing fees; per transaction rates; and actual and expected levels of customer participation.

During the first quarter of each calendar year, the Company will file with the Secretary to the Commission an annual report on expenditures associated with each type of credit/debit card transaction fee. At a minimum, this annual report will include an update on the expenditures associated with each type of per transaction customer fee, including per transaction fees charged to the Company; customer and processing fees; and the number of customers that use the Company's various payment methods.

Within 30 days of executing a contract with a third-party vendor, the Company will provide a customer outreach and education plan to the Secretary. Costs associated with outreach and education shall be included in the Credit/Debit Card Deferral described in Section V.B.4 herein.

2. Walk-In Payment Fees

The Company will eliminate per-transaction fees for customers who pay their bill at authorized payment locations.

Within six months after the Commission issues a final order in these proceedings, the Company shall file a proposal for Staff review regarding procedures for eliminating these charges at the authorized payment locations or for crediting customer accounts for charges imposed by authorized payment agents. Socialization of associated costs will be included in the Credit/Debit Card deferral.

3. Electronic Deferred Payment Agreements ("DPAs")

Within six months after the Commission issues a final order in these proceedings, the Company will conduct a study to gather information regarding what is required to implement an electronic DPA program (e.g., cost of an electronic DPA program, potential savings estimates, feasibility of linking an electronic DPA program to the Company's Customer Information System) and shall file a proposal for Staff review.

C. Training Materials and Customer Messaging

Central Hudson will enhance its Interactive Voice Response messages to include information regarding customers' rights for affordable payment agreements. In addition, the Company's training materials will be enhanced, as needed, to discuss the availability of, and the requirements for, enrollment in low income assistance programs. Where necessary, the Company's training materials will be updated regarding customers' options for "unsigned payment agreements" and/or DPAs and include language to provide customers with information on the features of each, including the terms of the relevant agreement.

Central Hudson will add the following language to its Interactive Voice Response messaging when a customer is in queue: "Need more time to pay your bill? Residential customers may be eligible for an affordable Deferred Payment Agreement with low monthly payments toward the past due balance. Please ask your Customer Service Representative for more details."

D. Recording Calls

Central Hudson will, to the extent practicable, continue to record outbound and inbound collection calls to and from the Company's call centers.

E. Written Confirmation of Unsigned Payment Agreements

Central Hudson will continue to maintain a record of unsigned payment agreements entered into the customer's account file. The Company is willing to conduct a study to gather information on what is required to implement an electronic DPA program and will, if implemented, instruct its Call Center Representatives to offer a written copy of all such agreements to the customer, and to furnish a written copy to each customer entering into such agreement by email, upon request.

XIX. OUTREACH AND EDUCATION

The Company will, during the term of this JP, continue to file an annual Outreach and Education Plan with the Secretary that is consistent in scope with plans filed by the Company under the 2015 Rate Order.

XX. OTHER GAS PROGRAMS

A. Benefit Cost Analysis

A Benefit Cost Analysis ("BCA") will be conducted for NPA projects or Gas Demand Response programs. It will be conducted using: (1) the societal cost test, utility cost test, and rate impact measure as set forth in the Commission's January 21, 2016 Order Establishing Benefit Cost Analysis Framework issued in the REV Proceeding ("BCA Order");[23] and (2) the framework provided within the Company's BCA handbook, including any environmental impacts caused by fuel switching, modified appropriately to address gas projects identified.

B. Participant Payback Tool

A tool will be provided to allow prospective customers to evaluate the costs and benefits of installing and operating different heating alternatives such as natural gas, air source heat pumps and geothermal heat pumps. Customers seeking to receive natural gas service will be made aware of environmentally beneficial heating options including Air Source and Ground Source Heat Pumps.

C. Non-Pipe Alternative Projects

Central Hudson will submit an implementation plan with the Secretary (to be made available on DMM in Case 17-E-0459 and Case 17-G-0460) for each identified NPA that includes, at a minimum, a detailed measurement and verification procedure(s), the solutions to be included, a demonstration of whether the costs of each NPA are incremental to the Company's revenue requirement or will be displacing a project subject to the Net Plant Reconciliation mechanism(s), and a customer and community outreach plan. Central Hudson will file updates to each implementation plan with the Secretary (to be made available on DMM in Cases 17-E-0459 and 17-G-0460) on an annual basis by December 1 of each year. The implementation plan will also

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[23] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing Benefit Cost Analysis Framework (Jan. 21, 2016).

include a BCA for each NPA identified, as described above. As stated in the BCA Order, the BCA should allow for consideration of factors other than the strict BCA outcome, and where appropriate, a qualitative assessment of non-qualified benefits.

The Company will hire a consultant to help develop the requirements necessary to issue an RFP and evaluate potential solutions for proposed NPA projects. Within 90 days of the Commission's issuance of a final order in these proceedings, the Company will facilitate a technical conference to review an example implementation plan, explain its BCA methodology, discuss the process used to evaluate and enact NPA projects, and review an example NPA incentive mechanism proposal. If a Signatory, or any party, has concerns about any aspect of the Company's NPA project(s), nothing in this JP should be construed to limit a party's ability to raise these concerns through public filings with the Commission and other action it may deem appropriate. The costs incurred and incentives earned by the Company for developing and implementing NPAs during this Rate Plan will be recovered through the Gas Miscellaneous Charge mechanism described in Section XII.K herein.

Within these proceedings, an NPA Incentive Mechanism will be established for future NPA Projects implemented after the Commission's issuance of a final order in these proceedings. The Company will establish an initial incentive ("Initial Incentive") equal to 30% of the present value of net benefits ("Initial Net Benefits"), i.e., the present value of net benefits projected at the time the Company has either entered into contracts with alternative solution providers for the NPA project portfolio, or when there is reasonable certainty on the price of the NPA project portfolio. To establish the Initial Incentive, the Company shall make a compliance filing. Prior to making its compliance filing to set the Initial Incentive, the Company shall seek input from Staff. Once the NPA project has been fully implemented, the Company will calculate the difference in the net present value ("NPV") of the NPA Project Cost, which will be equal to the NPV of the initially-forecasted NPA project cost, less the NPV of the actual NPA project. The Final Incentive will equal the sum of the Initial Incentive and ±50% of the difference in the NPV of the NPA Project Cost. The Final Incentive is subject to a floor of $0 and a cap of 50% of the Initial Net Benefits. Both the Initial Incentive and the Final Incentive calculations are subject to change based on Staff's review and audit.

Carrying charges earned on the unamortized balance associated with the NPA costs and incentives earned by the Company will be recovered in a manner similar to the recovery mechanism for NWA through the RAM.

D. Gas Demand Response Program

The Company will issue an RFP to solicit technology and fuel neutral market responses to a defined level of peak reduction. The Company will conduct an analysis including a BCA to determine the potential value of various levels of peak reduction provided by a Demand Response program. Following the implementation of a Gas Demand Response program, annual reports that include an updated BCA will be filed with the Secretary within 60 days of the end of each Rate Year.

E. Renewable Natural Gas

The Company shall file a renewable natural gas interconnect guidance document in the Company's Gas Transportation Operating Procedures ("GTOP") within 120 days of the Commission's issuance of a final order in these proceedings. Prior to making that filing, the Company shall seek input from Staff. Any GTOP filing will continue to be subject to the 30-day comment period.

F. Residential Methane Detection Program

Within 60 days of the Commission's issuance of a final order in these proceedings, the Company will file an implementation plan for its Residential Methane Detection Program. The Residential Methane Detection Program will be funded by NRAs as described in Section XVII.D herein. To the extent funding is exhausted, the Company may defer any program costs in excess of these amounts.

G. First Responder Training Program

Within 120 days of the Commission's issuance of a final order in these proceedings, the Company will file an implementation plan for its First Responder Training Program. The First Responder Training Program will be funded by NRAs as described in Section XVII.D herein. To the extent funding is exhausted, the Company may defer any program costs in excess of these amounts.

XXI. EARNINGS ADJUSTMENT MECHANISMS

Incentives associated with Electric EAMs will be recovered through the Miscellaneous Charges EAM Factor, which will be a component of the Company's Energy Cost Adjustment Mechanism. Recovery will be over a 12-month period commencing with the first billing batch in July following the EAM measurement period. Recovery will be on a kWh basis for non-demand customers and on a kW basis for demand customers, with rates determined for each service classification or sub-classification based on the aggregate results of the following allocation methodologies:

(1) Peak Reduction EAM: allocated using the transmission demand allocator;

(2) Energy Efficiency, Energy Intensity and Environmentally Beneficial Electrification EAMs: allocated using the energy allocator; and,

(3) DER Utilization EAM: allocated using three allocators which will be equally weighted (coincident peak, non-coincident peak, and energy allocator).

These rates will be applied to the energy (kWh) or demand (kW) deliveries, as applicable, on the bills of all customers served under SCs 1, 2, 3, 5, 6, 8, 9, 13, and 14. Customers taking service under SC 14 will be billed the rate applicable to their parent service classification, which is the service classification that the customer would otherwise qualify for based on the customer's usage characteristics.

Recoveries (11 months actual, one month forecast) will be reconciled to allocable costs for each 12-month recovery period ending June 30, with any over or under recoveries included in the development of succeeding Miscellaneous Charges EAM Factors. Reconciliation amounts related to the one month forecast will be included in the next subsequent rates determination.

For billing purposes, recovery for non-demand customers will be included in the Miscellaneous Charges, with the combined amount shown as one line item on customer bills. Cost recovery for demand customers will be through the Miscellaneous Charges II, a separate line item on customer bills.

Incentives associated with Gas EAMs will be recovered through the new Gas Miscellaneous Charge mechanism described in Section XII.K herein. Recovery will be over a 12-month period commencing with the first billing batch of July. Recovery will be on a Ccf basis with a uniform factor developed, based on forecast Ccf over the respective recovery period, and applied to all deliveries on the bills of all customers served under SCs 1, 2, 6, 11, 12, 13, 15 and 16. Recoveries (11 months actual, one month forecast) will be reconciled to allocable costs for each 12-month recovery period ending June 30, with any over or under recoveries included in the development of succeeding Miscellaneous Charges EAM Factors. Reconciliation amounts related to the one month forecast will be included in the next subsequent rates determination.

Central Hudson will adopt electric and gas EAMs as of July 1, 2018. Achievement of EAMs will be measured on December 31, 2018 and thereafter on a calendar year basis through calendar year 2021.[24] There are five EAMs for electric, comprised of a total of seven metrics, and one EAM for gas, comprised of one metric. Each EAM metric contains targets that are set at minimum, midpoint and maximum performance levels. The Company will earn a pre-tax earnings adjustment on a prorated basis for performance between the minimum and midpoint performance levels, and between the midpoint and maximum performance levels. Central Hudson has the potential to earn a maximum earnings adjustment of $2.0 million in 2018, $4.3 million in calendar year 2019, $4.7 million in calendar year 2020, and $4.9 million in calendar year 2021 for its electric business. With respect to the gas business, Central Hudson has the potential to earn a maximum earnings adjustment of $0.18 million in 2018, $0.39 million in calendar year 2019, $0.44 million in calendar year 2020, and $0.47

[24] The Company agrees not to file for modifications to the 2021 metrics and targets as part of a future rate filing, unless directed to do so by the Commission.

million in calendar year 2021. All EAM targets and incentives are set forth in Appendix W.

A. System Efficiency EAM

The System Efficiency EAM is composed of two metrics: Peak Reduction and Distributed Energy Resources ("DER") Utilization.

1. Peak Reduction (MW):

The Peak Reduction EAM metric incentivizes Central Hudson to reduce its New York State Independent System Operator ("NYISO") Zone G-J Locality peak. The Company will measure the weather-normalized Central Hudson system-wide demand at the hour of the NYISO Zone G-J Locality coincident peak in each measurement period, corrected for curtailments from contracted resources enrolled in the NYISO's Installed Capacity – Special Case Resources program during the NYISO Zone G-J Locality peak hour. The weather-normalization methodology will be based on the Company's annual submission to the NYISO of its weather-normalized NYCA coincident system peak.

The Company's Peak Reduction EAM targets and incentives are set forth in Appendix W.

2. DER Utilization

The DER Utilization EAM metric incentivizes Central Hudson to work with third parties to expand the use of DER resources in the Company's service territory. The DER metric will measure the sum of annualized MWh from incremental DER in Central Hudson's service territory, including large solar, combined heat and power, standalone or behind the meter electric energy storage resources, and fuel cells.

DER Utilization EAM targets and incentives are set forth in Appendix W.

B. Electric Energy Efficiency EAM

The Electric Energy Efficiency EAM is composed of three metrics: (1) Electric Energy Efficiency; (2) Residential Electric Energy Intensity; and (3) Commercial Electric Energy Intensity.

1. Electric Energy Efficiency (MWh)

The Electric Energy Efficiency EAM metric incentivizes the Company to achieve energy efficiency savings in calendar years 2018 through 2021 that are significantly above its historical first-year annual savings target of 34,240 MWh. This metric will be measured as the sum of MWh savings from all of Central Hudson's administered electric ETIP Energy Efficiency Programs, including behavioral programs, which may be utilized to achieve MWh targets. As a precondition to earning the incentive associated with this metric, the Estimated Useful Life ("EUL") of the Company's ETIP portfolio must be at least 90% of the current weighted average EUL for New York State utilities, and earnings related to this metric will be prorated between this level and the Company's historic EUL.

The Signatories agree that this Electric Energy Efficiency EAM is subject to change as a result of the Commission's action on Staff's upcoming Earth Day Energy Efficiency Targets/Funding proposal, which is due on or about Earth Day 2018 (April 22, 2018) per Governor Cuomo's State of the State directives and the Energy Efficiency Proceeding.

The Company's electric Energy Efficiency Program costs, which are subject to change pursuant to a Commission determination in the Energy Efficiency Proceeding, will be recovered in base rates beginning in Rate Year 1. Reconciliation of electric

Energy Efficiency Program costs will be aligned with established calendar year targets as described in Section XIII herein.

The Electric Energy Efficiency EAM metric targets and incentives are set forth in Appendix W.

2. Moderate Income Electric Energy Efficiency Proposal

During Rate Year 2, Central Hudson will implement an energy efficiency offering(s) targeted at Moderate Income customers. In developing the offering(s), the Company will collaborate with NYSERDA. By December 31, 2018, the Company will convene a meeting with interested parties to receive input on the Company's proposed offering(s). The details of the offering will be set forth in the Company's June 1, 2019 ETIP filing. The cost of the offering(s) will be funded from the established electric and gas ETIP budgets, as appropriate.

3. Residential Electric Energy Intensity Metric

The Residential Electric Energy Intensity EAM metric incentivizes Central Hudson to reduce residential (SCs 1 and 6) customers' total usage on a per customer basis. This metric will be measured as the sum of weather-normalized annual residential MWh sales adjusted for Community Distributed Generation allocations and increased sales due to beneficial electrification technologies, such as heat pumps and electric vehicles, divided by the 12-month average number of residential customers. The Residential Electric Energy Intensity metric targets and incentives are set forth in Appendix W.

4. Commercial Electric Energy Intensity Metric

The Commercial Electric Energy Intensity EAM metric incentivizes Central Hudson to reduce commercial (SC 2 non-demand) customers' total usage on a per customer basis. This metric will be measured as the sum of the weather-normalized annual commercial MWh sales adjusted for Community Distributed Generation allocations and increased sales due to beneficial electrification technologies such as heat pumps and electric vehicles, divided by the 12-month average number of commercial customers. The Commercial Electric Energy Intensity metric targets and incentives are set forth in Appendix W.

An Outreach and Education budget for the Electric Energy Intensity Metric has been included in rates as shown in Appendix A.

C. Customer Engagement EAM

The Customer Engagement EAM incentivizes the Company to increase residential customer participation in Voluntary Time of Use ("VTOU") rates. The Customer Engagement EAM measures the percentage of Central Hudson's residential customers that sign up for VTOU rates.

The Customer Engagement EAM targets and incentives are set forth in Appendix W.

D. Environmentally Beneficial Electrification EAM

The Environmentally Beneficial Electrification EAM metric incentivizes the Company to reduce carbon emissions by facilitating greater penetration of technologies that utilize electricity and reduce carbon emissions relative to traditional technologies that rely on more carbon intensive fuel sources. Examples of these technologies include geothermal heating and cooling, air source heat pumps for heating and cooling, and electric vehicles. The metric will be measured as the lifetime short tons of avoided carbon dioxide from environmentally beneficial electrification technologies as identified in the Company's Carbon Reduction Implementation Plan, which will be filed within 30 days of the Commission's issuance of a final order in these proceedings.

The Company will have the flexibility to adjust funding between Air-Source Heat Pump systems, Ground Source Heat Pump systems, and electric vehicles to optimize carbon reduction and market transformation. In addition, the Company will have the flexibility to allocate $4,526,879 of the ETIP budget to support its CRP instead as described in Section V.B.4. The CRP will utilize a portfolio approach similar to ETIPs, constrained by total budget and the portfolio passing the Societal Cost Test. During Rate Year 1, the Company will evaluate electric vehicle programs to be included in the Carbon Reduction Implementation Plan filed in June 2019.

The Environmentally Beneficial Electrification EAM targets and incentives are set forth in Appendix X.

E. Interconnection

The Company may petition the Commission for approval of metrics and targets consistent with a future Commission order regarding the Interconnection EAM Metric in Case 16-M-0429, <u>In the Matter of Earnings Adjustment Mechanism and Scorecard Reforms Supporting the Commission's Reforming the Energy Vision</u>. The Company will reserve 1 BP Minimum, 2.5 BP Midpoint, and 5 BP at Maximum for interconnection related EAMs in total.

F. Gas Energy Efficiency EAM (Dth)

The Gas Energy Efficiency EAM incentivizes the Company to achieve energy efficiency savings that are significantly above its historical first-year annual savings target of 37,296 Dth for calendar years 2018 through 2021. This metric will be measured as the sum of Dth savings from all of Central Hudson's administered gas ETIP Energy Efficiency Programs. As a precondition to earning the incentive associated with this metric, the EUL of the Company's ETIP portfolio must be at least 90% of its historic EUL for Central Hudson's Gas ETIP portfolio, and earnings related to this metric will be prorated between this level and the Company's historic EUL.

The Signatories agree that this Gas Energy Efficiency EAM is subject to change as a result of the Commission's action on Staff's upcoming Earth Day Energy Efficiency Targets/Funding proposal, which is due on Earth Day 2018 (on/about April 22, 2018) per Governor Cuomo's State of the State directives and the Energy Efficiency Proceeding.

The Company's gas Energy Efficiency Program costs, which are subject to change pursuant to a Commission determination in the Energy Efficiency Proceeding, will be recovered in base rates beginning in Rate Year 1. Reconciliation of gas Energy Efficiency Program costs will be aligned with established calendar year targets as described in Section XIII herein. The Gas Energy Efficiency EAM targets and incentives are set forth in Appendix W.

XXII. GEOTHERMAL RATE IMPACT CREDIT

Central Hudson will develop a Geothermal "Rate Impact Credit" program to be implemented for Rate Year 1, Rate Year 2 and Rate Year 3 subject to the conditions described below. In order to qualify for the rate impact credit, equipment installed must meet requirements applicable to the NYSERDA Geothermal Rebate Program.

The participant rate impact credit will be funded by incremental heating usage that would be monetized and provided to non-participants through the RDM. While the rate impact credit will not be included within the CRP funding cap, any outreach, education, or implementation funding for this program will be included within the CRP funding cap. The rate impact credit will be paid to participating customers on an annual basis on June 30 of each year. In order to be eligible for the rate impact credit, the customer will be required to enroll in the Company's Insights+ offering.[25] Following the development of a technology agnostic DER or mass market default rate or a rate that is specifically intended to mitigate the rate impact of geothermal heat pump systems, no further rate impact credits will be paid out. It is expected that this rate will be designed as part of Case 15-M-0751, Value of Distributed Energy Resources.

The annual rate impact credit will be $264.

XXIII. NWA INCENTIVE MECHANISM

The Company will continue to earn, record, and report incentives associated with its current NWA Programs as authorized by the Order Implementing with Modification the Proposal for Cost Recovery and Incentive Mechanism for Non-Wire Alternative Project issued on July 15, 2016 in Case 14-E-0318[26] and the subsequent Operating and Accounting Procedures filed with the Secretary as directed within that Order. Within

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25 The Company's Insights+ program is currently being offered at a subsidized monthly rate of $4.99/month, which is effective while the Insights+ offering remains a demonstration project.

26 Case 14-E-0318, Order Implementing with Modification the Proposal for Cost Recovery and Incentive Mechanism for Non-Wire Alternative Project (July 15, 2016).

these proceedings, a new NWA Incentive Mechanism establishes an incentive mechanism for future NWA Projects implemented following the Commission's issuance of a final order in these proceedings. The new NWA Incentive Mechanism is described in Appendix X.

XXIV. PLATFORM SERVICE REVENUES AND DEMONSTRATION PROJECTS

A. CenHub Platform

On July 1, 2015 in the REV Proceeding, Central Hudson submitted a Demonstration Project Report to Staff seeking to develop and implement the CenHub Platform demonstration project (initially entitled Central-E). On November 10, 2015, Staff filed its Assessment Report that concluded that Central Hudson's CenHub demonstration project complies with the requirements of the Order Adopting Regulatory Policy Framework and Implementation Plan issued on February 26, 2015 in the REV Proceeding.[27] Central Hudson subsequently filed its CenHub Implementation Plan and Quarterly Implementation Status reports. On April 3, 2016, the CenHub Platform was made available to Central Hudson's customers and as of December 31, 2017, 42% of Central Hudson's customers have engaged with the CenHub Platform. The CenHub Platform has improved the relationship and depth of engagement between Central Hudson and its customers and following an order in these proceedings will no longer be considered a demonstration project and will be funded through base rates instead of the demonstration project deferral mechanism as described in Section V.B.1.

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[27] Case 14-M-0101, Order Adopting Regulatory Policy Framework and Implementation Plan (Feb. 26, 2015).

The CenHub platform also generates Platform Service Revenues ("PSRs") from the sale of energy-related products and services on the CenHub store. Following the Commission's issuance of a final order in these proceedings, any revenues that Central Hudson receives from the CenHub store will be shared 80/20 between customers and the Company as a PSR. This PSR will be excluded from the calculation of the Company's regulatory earnings.

B. Insights+ Platform

Insights+ is a subscription based offering provided on the CenHub Platform. Specifically, the Insights+ offering allows customers the ability to enroll in a voluntary, subscription based service that introduces enhancements to the current Insights experience. The program includes replacement of the customer's existing house meter with an Insights+ meter and the ability to view hourly usage data. The Insights+ offering was made available to customers beginning on June 6, 2017 and has not been available to customers for a sufficient amount of time to test the value that can be provided to customers. As such, the Insights+ offering will continue as a demonstration project following the Commission's issuance of a final order in these proceedings.

XXV. MISCELLANEOUS PROVISIONS

A. Rate Changes; Reservation of Authority

Nothing herein precludes Central Hudson from filing a new general rate case for rates to be effective on or after July 1, 2021. Except pursuant to rate changes permitted by this section, the Company will not file rates to become effective prior to July 1, 2021.

Changes to the Company's base delivery service rates during the term of this Rate Plan will not be permitted, except for the changes provided for or detailed in this

Proposal, and, subject to Commission approval, changes as a result of the following circumstances.

(1) A minor change, whose revenue effect is *de minimis* or essentially offset by associated changes within the same class or for other classes so that the difference in the revenues that the Company's base delivery service rates are designed to produce overall before such a change is *de minimis*, may be made to any individual base delivery service rate or rates. It is understood that, over time, such minor changes may be necessary and that they may continue to be sought during the term of this Rate Plan.

(2) Upon the occurrence, at any time, of circumstances that in the judgment of the Commission so threaten, respectively, the Company's economic viability or ability to maintain safe, reliable and adequate service as to warrant an exception to the limitations on rate changes provided for or detailed in this Proposal, Central Hudson will be permitted to file for an increase in base delivery service rates. The Signatories reserve the right to oppose any filings made under this Section.

(3) The Signatories recognize that the Commission reserves the authority to act on the level of the Company's rates in the event of unforeseen circumstances that, in the Commission's opinion, have such a substantial impact on the range of earnings levels or equity costs envisioned by this Proposal as to render the Company's rates unjust or unreasonable or insufficient for the provision of safe and adequate service. The Signatories reserve the right to oppose any filings made under this Section.

The terms of this JP may be subject to updates that arise out of generic Commission proceedings, including but not limited to: (1) the REV Proceeding; (2) Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources; (3) the Energy Efficiency Proceeding; and (4) Case 17-M-0815, Proceeding on Motion of the Commission on Changes in Law that May Affect Rates.

B. Provisions Not Separable

The Signatories intend this Proposal to be a complete resolution of all the issues in Cases 17-E-0459 and 17-G-0460.[28] The terms of this Proposal are submitted as an integrated whole. If the Commission does not accept this Proposal according to its terms as the basis of the resolution of all issues addressed without change or condition, each Signatory shall have the right to withdraw from this Proposal upon written notice to the Commission within ten days of the Commission Order. Upon such a withdrawal, that Signatory shall be free to pursue its respective positions in these proceedings without prejudice, and this Proposal shall not be used in evidence or cited against any such Signatory or used for any other purpose. It is also understood that each provision of this Proposal is in consideration and support of all the other provisions, and expressly conditioned upon by the Commission. Except as set forth herein, none of the Signatories is deemed to have approved, agreed to or consented to any principle, methodology or interpretation of law underlying or supposed to underlie any provision herein.

[28] The Signatories have agreed to a process to address further actions to be taken in the future to fully effectuate this Proposal. See Section XXV.H ("Further Assurances").

C. Provisions Not Precedent

The terms and provisions of this Proposal apply solely to, and are binding only in, the context of the purposes and results of this Proposal. None of the terms or provisions of this Proposal, nor any methodology or principle utilized herein, and none of the positions taken herein by any Signatory Party may be referred to, cited, or relied upon by any other Signatory Party in any fashion as precedent or otherwise in any other proceeding before this Commission or any other regulatory agency or before any court of law for any purpose other than furtherance of the purposes, results, and disposition of matters governed by this Proposal and except as may be necessary in explaining derivation of specific costs or accounting treatments as relevant to future ratemaking proceedings. Concessions made by Signatories on various electric and gas issues included in the JP do not preclude those parties from addressing such issues in future rate proceedings or in other proceedings. This Proposal shall not be construed, interpreted or otherwise deemed in any respect to constitute an admission by any Signatory regarding any allegation, contention, or issue rose in these proceedings or addressed in this Proposal.

D. Submission of Proposal

Each Signatory Party agrees to submit this Proposal to the Commission, to support and request its adoption by the Commission, and not to take a position in these proceedings contrary to the agreements set forth herein or to assist another participant in taking such a contrary position in these proceedings. The Signatories believe that the resolution of the issues, as set forth in the Proposal, is just and reasonable and otherwise in accordance with the New York State Public Service Law (“PSL”), the

Commission's regulations and applicable Commission precedent. The Signatories believe that the Proposal will satisfy the requirements of PSL § 65(1) that Central Hudson provide safe and adequate service at just and reasonable rates.

E. Trade Secret Protections

Nothing in this document prevents Central Hudson from seeking trade secret protection under 16 NYCRR Part 6 for all or any part(s) of any document or report filed (or submitted to Staff) in accordance with this Rate Plan, or prohibits or restricts any other party from challenging any such request.

F. Dispute Resolution

In the event of any disagreement over the interpretation of this JP or the implementation of any of the provisions of this JP which cannot be resolved informally among the parties, such disagreement will be resolved as follows: the parties promptly will confer and in good faith, will attempt to resolve such disagreement. If any such disagreement cannot be resolved by the parties, then the matter will be submitted to an ALJ designated by the Chief ALJ for a determination on an expedited basis using alternative dispute resolution techniques or such other procedures as the ALJ decides are appropriate under the circumstances. Within 15 days from the ALJ's decision, any party may petition the Commission for relief from the ALJ's determination on the disputed matter.

G. Effect of Commission Adoption of Terms of this Proposal

No provision of this Proposal or the Commission's adoption of the terms of this Proposal shall in any way abrogate or limit the Commission's statutory authority under the PSL. The Signatories recognize that any Commission adoption of the terms of this

Proposal does not waive the Commission's ongoing rights and responsibilities to enforce its orders and effectuate the goals expressed therein, nor the rights and responsibilities of Staff to conduct investigations or take other actions in furtherance of its duties and responsibilities.

H. Further Assurances

The Signatories recognize that certain provisions of this Proposal require that actions be taken in the future to fully effectuate this Proposal. Accordingly, the Signatories agree to cooperate with each other in good faith in taking such actions.

I. Execution

This Proposal may be executed in one or more counterparts, all of which taken together shall constitute one and the same instrument which shall be binding upon each Signatory Party when its executed counterpart is filed with the Secretary. This JP will be binding on each and every Signatory when the counterparts have been executed. In the event that any signature is delivered by facsimile transmission or by e-mail delivery of a "pdf" format data file, such signature shall create a valid and binding obligation of the party executing (or on whose behalf such signature is executed) with the same force and effect as if such facsimile or "pdf" signature page were an original thereof.

J. Entire Agreement

This Proposal, including all attachments, exhibits and appendices, if any, represents the entire agreement of the Signatories with respect to the matters resolved herein.

IN WITNESS WHEREOF, the Signatories hereto have affixed their signatures below as evidence of their agreement to be bound by the provisions of this Proposal.

WHEREFORE, this JP in Cases 17-E-0459 and 17-G-0460 has been agreed to as of the 14 day of March, 2018, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Anthony Campagiorni

Anthony S. Campagiorni
Vice-President
Regulatory & Governmental Affairs
Central Hudson Gas & Electric Corporation

WHEREFORE, this JP in Cases 17-E-0459 and 17-G-0460 has been agreed to as of the 17th day of April, 2018, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

John Favreau
Assistant Counsel
New York State Department of Public Service

WHEREFORE, this JP in Cases 17-E-0459 and 17-G-0460 has been agreed to as of the 12th day of March, 2018, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Michael B. Mager

Michael B. Mager
Couch White, LLP
Counsel for Multiple Intervenors

WHEREFORE, this JP in Cases 17-E-0459 and 17-G-0460 has been agreed to as of the 15th day of March, 2018, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Radina Valova

Radina Valova
Senior Staff Attorney & Litigation Manager
Pace Energy and Climate Center

WHEREFORE, this JP in Cases 17-E-0459 and 17-G-0460 has been agreed to as of the 13th day of March, 2018, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Bill Nowak

Bill Nowak
Executive Director
NY-GEO

WHEREFORE, this JP in Cases 17-E-0459 and 17-G-0460 has been agreed to as of the 12 day of March, 2018, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Erin Hogan
Director, Utility Intervention Unit
New York State Department of State,
Division of Consumer Protection

WHEREFORE, this JP in Cases 17-E-0459 and 17-G-0460 has been agreed to as of the 12th day of March, 2018, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

William F.X. O'Neil
Deputy County Executive
Dutchess County

Based upon the impact of Central Hudson above referenced rate cases on Dutchess County citizens, the County sought active party status which the Public Service Commission granted in the proceedings. The County filed direct testimony and has participated in the majority of the Settlement negotiations on the cases. The County supports the Settlement negotiated by the Public Service Commission, Central Hudson,
and active parties in the cases. The Settlement balances a significant set of competing interests that have been drawn into the cases. Ultimately the Commission must provide a viable path forward for Central Hudson customers to receive reliable quality service at the lowest reasonable price maintaining a sound gas and electric infrastructure and a financially viable entity that delivers the services. The County believes the process has
accomplished this objective in this Settlement. However the proceeding has raised issues which are of concern to Dutchess County and which need to be addressed on a State wide basis in the future.

1) The County believes that State wide energy policy reflecting carbon reduction is best placed within the legislature for implementation through appropriately levied taxes and should not be a basis for raising gas and electric PSC jurisdictional customer billing.

2) Rate case active party participation should be limited to organizations or parties directly impacted by rate case outcomes. Rate cases now have active party participation which provides a platform for broad State wide policy initiatives, promoting market based technologies and products, or general regulatory education. Such participation ties up valuable resources that otherwise would be directed toward a complete, informed, and valuable proceeding record directly benefiting Central Hudson gas and electric customers.

3) The Commission should reaffirm its primary objective for such cases i.e., the delivery of just and reasonably priced electric and gas service.

Cases 17-E-0459 and 17-G-0460

Acadia Center has this day signed and executed this Joint Proposal.

By: Cullen Howe

Cullen Howe
Senior Attorney and New York Director

Date: March 13, 2018

WHEREFORE, this JP in Cases 17-E-0459 and 17-G-0460 has been agreed to as of the ___ day of March, 2018, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Richard Berkley
Executive Director
Public Utility Law Project of New York

Case 17-E-0459

The Natural Resources Defense Council (NRDC) participated in negotiations of this Joint Proposal only with regard to energy efficiency programs, discussed in Sections XIII and XXI of the Joint Proposal, and the reduction of monthly customer charges, discussed in Section X of the Joint Proposal. NRDC is therefore agreeing only to those portions of the Joint Proposal pertaining to those provisions. NRDC takes no position regarding the remaining portions of the Joint Proposal.

NATURAL RESOURCES DEFENSE COUNCIL

Dated: 3/14/2018 By: ____________________

WHEREFORE, this JP in Cases 17-E-0459 and 17-G-0460 has been agreed to as of the 13th day of March, 2018, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Bob Wyman
203 W 85th St.
Apt PH2
New York, NY 10024

WHEREFORE, this JP has been agreed to as of the 13th day of March, 2018, by and among the following, each of whom, by its signature, represents that he is fully authorized to execute this JP and, if executing this JP in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

Matthew Dunne
General Attorney
U.S. Army Legal Services Agency
on behalf of U.S. Department of Defense and all other Federal Executive Agencies

Appendix A, Schedule 1

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Income Statements
($000)

	Rate Years Ending		
	6/30/19	6/30/20	6/30/21
Operating Revenues			
Delivery Revenues - Before Increase	315,497	332,852	348,476
Rate Increase	19,725	18,581	25,083
Revenue Taxes	6,275	6,776	7,446
Other Operating Revenues	10,466	10,811	11,129
Total Operating Revenues	351,963	369,020	392,134
Operating Expenses			
Labor	62,228	64,502	66,554
Executive Incentive Compensation	491	506	521
Employee Benefits	10,222	10,620	10,961
Pension Plan	8,485	1,822	1,448
Other Post Employee Benefits	(6,306)	(5,585)	(4,596)
Employee Training, Safety & Education	1,602	1,636	1,670
Production Maintenance	255	260	265
Right of Way Maintenance - Transmission	3,500	2,900	2,614
Right of Way Maintenance - Distribution	19,588	19,999	20,419
Stray Voltage Testing	568	580	592
System Engineering & Compliance	226	231	236
Substation Testing & Maintenance	571	583	595
Transmission Repairs & Maintenance	1,430	1,460	1,491
Distribution Repairs & Maintenance	3,795	4,097	4,018
Transformer Installations & Removals	(653)	(667)	(681)
Meter Installations, Removals & Maintenance	(884)	(903)	(922)
Research and Development	2,537	2,590	2,644
Informational & Instituational Advertising	570	588	611
Meter Reading & Collections	1,609	1,643	1,678
Bill Print	496	506	517
Postage	1,262	1,289	1,316
Payment by Credit/Debit Card	344	811	1,030
Low Income Program	5,882	7,371	8,033
Uncollectible Accounts	2,853	2,992	3,182
Regulatory Commission General Assessment	2,092	2,136	2,181
Environmental SIR Costs	6,714	6,855	6,999
Environmental All Other	169	173	177
Information Technology	7,285	8,726	10,371
Telephone	1,595	1,628	1,662
Rental Agreements	1,992	2,034	2,077
Security of Infrastructure	1,913	1,953	2,088
Maintenance of Buildings & Grounds	1,537	1,569	1,602
Major Storm Reserve	1,558	1,558	1,558
Non Major Storm Restoration	4,682	4,780	4,880
Material & Supplies	1,658	1,693	1,729
Stores Clearing to Expense	95	97	99
Transportation - Depreciation	2,508	2,679	2,832
Transportation - Fuel	901	920	939
Transportation - All Other	1,012	1,033	1,055
Rate Case Expenses	460	460	460
Legal Services	839	857	875
Consulting & Professional Services	2,828	2,973	3,133
Miscellaneous General Expenses	3,949	4,032	4,117
Injuries and Damages	2,703	2,760	2,818
Other Operating Insurance	660	674	688
Office Supplies	1,130	1,154	1,178
Management & Operational Audit Costs	72	72	72
Energy Efficiency	9,773	9,773	9,773
Carbon Reduction	350	350	350
Energy Intensity	200	204	208
Expenses Allocated to Affiliates	(2)	(2)	(2)
Miscellaneous Charges	787	804	821
Productivity Imputation	(1,187)	(1,140)	(1,190)
Total Operating Expenses	178,945	180,636	187,746
Other Deductions			
Property Taxes	38,833	41,535	44,234
Revenue Taxes	6,275	6,776	7,446
Payroll Taxes	4,473	4,633	4,778
Other Taxes	3,275	3,344	3,414
Depreciation	45,292	50,255	54,893
Total Other Deductions	98,148	106,543	114,765
State Income Taxes	3,175	3,468	3,948
Federal Income Taxes	7,328	8,232	9,772
Total Income Taxes	10,503	11,700	13,719
Total Operating Revenue Deductions	287,596	298,879	316,231
Operating Income	$64,367	$70,142	$75,903
Rate Base	$999,482	$1,080,768	$1,160,578
Rate of Return	6.44%	6.49%	6.54%

Appendix A, Schedule 2

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Gas Income Statements
($000)

	Rate Years Ending		
	6/30/19	6/30/20	6/30/21
Operating Revenues			
Delivery Revenues - Before Increase	94,674	102,584	110,546
Rate Increase	6,654	6,702	8,183
Revenue Taxes	2,074	2,326	2,633
Interruptible Imputation	2,600	2,600	2,600
Other Operating Revenues	1,067	1,135	1,221
Total Operating Revenues	107,068	115,347	125,182
Operating Expenses			
Labor	19,158	19,847	20,469
Executive Incentive Compensation	123	127	131
Employee Benefits	3,012	3,130	3,231
Pension Plan	2,418	742	639
Other Post Employee Benefits (OPEB)	(1,532)	(1,354)	(1,109)
Employee Training, Safety & Education	659	673	687
System Engineering & Compliance	69	70	71
T&D Repairs & Maintenance	1,810	1,848	1,887
Pipeline Integrity & Inspection	1,985	2,027	2,070
Gas Leak Repairs - Distribution Main	1,527	1,445	1,448
Meter Installations, Removals & Maintenance	(147)	(150)	(153)
Research and Development	603	616	629
Gas Connections	395	403	411
Informational & Instituational Advertising	151	159	169
Meter Reading & Collections	403	411	420
Bill Print	124	127	130
Postage	316	323	330
Payment by Credit/Debit Card	109	256	325
Low Income Program	2,923	3,701	4,036
Uncollectible Accounts	1,060	1,142	1,238
Regulatory Commission General Assessment	506	517	528
Environmental SIR Costs	1,679	1,714	1,750
Environmental All Other	67	68	69
Information Technology	1,924	2,278	2,685
Telephone	342	349	356
Rental Agreements	331	338	345
Security of Infrastructure	479	489	523
Maintenance of Buildings & Grounds	301	307	313
Material & Supplies	426	435	444
Stores Clearing to Expense	27	28	29
Transportation - Depreciation	720	769	813
Transportation - Fuel	260	265	271
Transportation - All Other	454	464	474
Rate Case Expenses	115	115	115
Legal Services	244	249	254
Consulting & Professional Services	659	694	733
Miscellaneous General Expenses	1,008	1,029	1,051
Injuries and Damages	736	751	767
Other Operating Insurance	97	99	101
Office Supplies	287	293	299
Management & Operational Audit Costs	20	20	20
Energy Efficiency	1,182	1,182	1,182
Expenses Allocated to Affiliates	-	-	-
Miscellaneous Charges	429	438	447
Productivity Imputation	(366)	(356)	(371)
Total Operating Expenses	47,093	48,078	50,257
Other Deductions			
Property Taxes	13,095	14,453	16,100
Revenue Taxes	2,074	2,326	2,633
Payroll Taxes	1,330	1,378	1,421
Other Taxes	691	706	721
Depreciation	13,794	15,570	17,244
Total Other Deductions	30,984	34,433	38,119
State Income Taxes	1,415	1,580	1,764
Federal Income Taxes	3,845	4,397	5,015
Total Income Taxes	5,260	5,977	6,778
Total Operating Revenue Deductions	83,337	88,488	95,154
Operating Income	$23,731	$26,859	$30,028
Rate Base	$368,521	$413,857	$459,155
Rate of Return	6.44%	6.49%	6.54%

Appendix A, Schedule 3

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Rate Base
($000)

	Rate Years Ending		
	6/30/19	6/30/20	6/30/21
Book Cost of Utility Plant	$1,673,283	$1,777,593	$1,887,099
Less: Accumulated Provision for Depreciation and Amortization	(449,615)	(469,265)	(493,703)
Net Plant	1,223,668	1,308,328	1,393,396
Noninterest-Bearing Construction Work in Progress	22,082	28,267	27,739
Customer Advances for Undergrounding	(444)	(444)	(444)
Deferred Charges	(136,592)	(134,174)	(128,769)
Accumulated Deferred Federal Taxes	(139,017)	(148,907)	(157,488)
Accumulated Deferred State Taxes	(24,517)	(28,198)	(32,083)
Working Capital	54,720	56,314	58,645
Unadjusted Rate Base	999,900	1,081,186	1,160,996
Capitalization Adjustment to Rate Base	(418)	(418)	(418)
Total	$999,482	$1,080,768	$1,160,578

Appendix A, Schedule 4

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Gas Rate Base
($000)

	Rate Years Ending		
	6/30/19	6/30/20	6/30/21
Book Cost of Utility Plant	$604,248	$667,162	$728,482
Less: Accumulated Provision for Depreciation and Amortization	(149,411)	(157,155)	(166,606)
Net Plant	454,837	510,007	561,876
Noninterest-Bearing Construction Work in Progress	18,763	16,382	15,969
Customer Advances for Undergrounding	(361)	(361)	(361)
Deferred Charges	(62,228)	(62,840)	(62,856)
Accumulated Deferred Federal Taxes	(46,672)	(52,123)	(56,979)
Accumulated Deferred State Taxes	(10,189)	(12,100)	(14,075)
Working Capital	14,510	15,031	15,720
Unadjusted Rate Base	368,660	413,996	459,294
Capitalization Adjustment to Rate Base	(139)	(139)	(139)
Total	$368,521	$413,857	$459,155

Appendix B Sheet 1 of 2

Central Hudson Gas & Electric Corporation

Cases 17-E-0459 & 17-G-0460

Illustrative Example of Make Whole Provision - Electric

	Jul-18			Current Rates				Proposed Rates				New Rate	Unrealized
	Custs/Faces	kWh	kW	Cust. Chg.	kWh	MFC kWh	kW	Cust. Chg.	kWh	MFC kWh	kW	Proration	Revenue
SC 1 Residential	257,341	149,008,346		$ 24.00	$ 0.06586	$ 0.00399		$ 21.00	$ 0.07563	$ 0.00485		45.8%	$ 371,867
SC 2 Non Demand	29,137	11,776,194		$ 35.00	$ 0.02702	$ 0.00562		$ 32.00	$ 0.03887	$ 0.00689		43.9%	$ 29,454
SC 2 Secondary	11,703	127,034,530	423,449	$ 84.00	$ 0.00591	$ 0.00027	$ 9.06	$ 88.00	$ 0.00532	$ 0.00030	$ 10.28	54.0%	$ 265,832
SC 2 Primary	155	18,577,000	53,079	$ 310.00	$ 0.00168	$ 0.00002	$ 7.64	$ 341.00	$ 0.00151	$ 0.00003	$ 8.63	65.0%	$ 35,348
SC 3 Primary	31	24,544,960	53,359	$ 1,500.00			$ 9.84	$ 1,650.00			$ 10.99	100.0%	$ 66,012
SC 5 Area Lighting **	4,025	802,035		$ 137,303.00		$ 0.01045		$ 143,682.00		$ 0.01194		45.8%	$ 3,469
SC 6 Residential TOU on pk	990	651,000		$ 27.00	$ 0.09507	$ 0.00183		$ 24.00	$ 0.10520	$ 0.00193		45.8%	$ 1,690
SC 6 Residential TOU off pk		1,519,000			$ 0.03169	$ 0.00183			$ 0.03507	$ 0.00193		45.8%	$ 2,421
SC 8 Street Lighting **	210	1,160,000		$ 419,164.00		$ 0.00030		$ 437,279.00		$ 0.00045		54.0%	$ 9,876
SC 9 Traffic Signals	5,155	200,000		$ 3.52		$ 0.00283		$ 3.68		$ 0.00307		100.0%	$ 873
SC 13 Substation	8	15,136,000	20,830	$ 3,800.00			$ 7.49	$ 4,200.00			$ 9.25	100.0%	$ 39,861
SC 13 Transmission	5	64,732,000	103,640	$ 5,020.00			$ 4.30	$ 6,500.00			$ 4.62	100.0%	$ 40,565
Total													**$ 867,266**

	Aug-18			Current Rates				Proposed Rates				Rate	Unrealized
	Custs/Faces	kWh	kW	Cust. Chg.	kWh	MFC kWh	kW	Cust. Chg.	kWh	MFC kWh	kW	Proration	Revenue
SC 1 Residential	257,838	177,129,032		$ 24.00	$ 0.06586	$ 0.00399		$ 21.00	$ 0.07563	$ 0.00485		100.0%	$ 1,109,368
SC 2 Non Demand	30,177	13,620,983		$ 35.00	$ 0.02702	$ 0.00562		$ 32.00	$ 0.03887	$ 0.00689		100.0%	$ 88,176
SC 2 Secondary	11,676	130,547,289	401,684	$ 84.00	$ 0.00591	$ 0.00027	$ 9.06	$ 88.00	$ 0.00532	$ 0.00030	$ 10.28	100.0%	$ 463,652
SC 2 Primary	155	19,407,000	48,518	$ 310.00	$ 0.00168	$ 0.00002	$ 7.64	$ 341.00	$ 0.00151	$ 0.00003	$ 8.63	100.0%	$ 49,733
SC 3 Primary	32	24,931,416	50,880	$ 1,500.00			$ 9.84	$ 1,650.00			$ 10.99	100.0%	$ 63,313
SC 5 Area Lighting	4,006	895,844		$ 137,303.00		$ 0.01045		$ 143,682.00		$ 0.01194		100.0%	$ 7,714
SC 6 Residential TOU on pk	1,010	495,000		$ 27.00	$ 0.09507	$ 0.00183		$ 24.00	$ 0.10520	$ 0.00193		100.0%	$ 2,034
SC 6 Residential TOU off pk		1,155,000			$ 0.03169	$ 0.00183			$ 0.03507	$ 0.00193		100.0%	$ 4,019
SC 8 Street Lighting	210	1,300,000		$ 419,164.00		$ 0.00030		$ 437,279.00		$ 0.00045		100.0%	$ 18,310
SC 9 Traffic Signals	5,145	200,000		$ 3.52		$ 0.00283		$ 3.68		$ 0.00307		100.0%	$ 871
SC 13 Substation	8	15,290,000	20731	$ 3,800.00			$ 7.49	$ 4,200.00			$ 9.25	100.0%	$ 39,687
SC 13 Transmission	5	65,304,000	109,304	$ 5,020.00			$ 4.30	$ 6,500.00			$ 4.62	100.0%	$ 42,377
Total													**$ 1,889,253**

** Total fixture revenue included in Cust. Chg. Column.

Appendix B Sheet 2 of 2
Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Illustrative Example of Make Whole Provision - Gas

	Jul-18			Current Rates				Proposed Rates				New Rate	Unrealized
	Customers	Mcf	MDQ	Cust. Chg.	Ccf	MFC Ccf	MDQ	Cust. Chg.	Ccf	MFC Ccf	MDQ	Proration	Revenue
SC 1/ 12 Residential													
Block 1	69,788	12,999		$ 26.00				$ 25.00				45.6%	$ (31,823)
Block 2		126,223			$ 0.99040				$ 1.10500				$ 65,961
Block 3		12,738			$ 0.45420				$ 0.50600				$ 3,009
MFC						$ 0.01731				$ 0.02605			$ 6,056
SC 2/6/13 Non-Residential													
Block 1	11,734	1,546		$ 39.00				$ 39.00				43.0%	$ -
Block 2		38,562			$ 0.54940				$ 0.58360				$ 5,671
Block 3		136,122			$ 0.32620				$ 0.34640				$ 11,824
Block 4		68,442			$ 0.26560				$ 0.28190				$ 4,797
MFC						$ 0.01670				$ 0.02855			$ 12,467
SC 11 DLM													
first 300,000 Ccf	1	30,000	4,900	$ 50,600.00									
Additional		634			$ 0.05990								
first 1,000 Ccf								$ 6,000.00					$ (44,600)
Additional									$ 0.01980		$ 11.73	100.0%	$ 63,143
SC 11 D													
(Annual x<100k Mcf)													
first 40,000 Ccf	1	3,410	353	$ 7,500.00									
Additional		-			$ 0.06390								
first 1,000 Ccf								$ 1,000.00					$ (6,500)
Additional									$ 0.03120		$ 16.66	100.0%	$ 6,914
SC 11 T													
(Annual x<300k Mcf)													
first 50,000 Ccf	1	5,000	913	$ 7,500.00									
Additional		10,680			$ 0.02980								
(Annual 300k<x<800k Mcf)													
first 100,000 Ccf	1	10,000	7,607	$ 38,200.00									
Additional		21,040			$ 0.04470								
first 1,000 Ccf								$ 3,000.00					$ (39,700)
Additional									$ 0.01480		$ 7.02	100.0%	$ 54,123
SC 11 EG	1		5,000	$ 1,200.00			$ 9.25	$ 1,500.00			$ 9.88	100.0%	$ 3,450
Total													**$ 114,791**

	Aug-18			Current Rates				Proposed Rates				Rate	Unrealized
	Customers	Mcf	MDQ	Cust. Chg.	kWh	MFC kWh	kW	Cust. Chg.	kWh	MFC kWh	kW	Proration	Revenue
SC 1/ 12 Residential													
Block 1	69,840	12,675		$ 26.00				$ 25.00				100.0%	$ (69,840)
Block 2		88,469			$ 0.99040				$ 1.10500				$ 101,385
Block 3		4,438			$ 0.45420				$ 0.50600				$ 2,299
MFC						$ 0.01731				$ 0.02605			$ 9,228
SC 2/6/13 Non-Residential													
Block 1	11,757	1,384		$ 39.00				$ 39.00				100.0%	$ -
Block 2		31,889			$ 0.54940				$ 0.58360				$ 10,906
Block 3		104,897			$ 0.32620				$ 0.34640				$ 21,189
Block 4		51,371			$ 0.26560				$ 0.28190				$ 8,373
MFC						$ 0.01670				$ 0.02855			$ 22,461
SC 11 DLM													
first 300,000 Ccf	1	30,000	4,900	$ 50,600.00									
Additional		928			$ 0.05990								
first 1,000 Ccf								$ 6,000.00					$ (44,600)
Additional									$ 0.01980		$ 11.73	100.0%	$ 63,025
SC 11 D													
(Annual x<100k Mcf)													
first 40,000 Ccf	1	3,860	353	$ 7,500.00									
Additional		-			$ 0.06390								
first 1,000 Ccf								$ 1,000.00					$ (6,500)
Additional									$ 0.03120		$ 16.66	100.0%	$ 7,054
SC 11 T													
(Annual x<300k Mcf)													
first 50,000 Ccf	1	5,000	913	$ 7,500.00									
Additional		10,520			$ 0.02980								
(Annual 300k<x<800k Mcf)													
first 100,000 Ccf	1	10,000	7,607	$ 38,200.00									
Additional		20,630			$ 0.04470								
first 1,000 Ccf								$ 3,000.00					$ (39,700)
Additional									$ 0.01480		$ 7.02	100.0%	$ 54,269
SC 11 EG	1		5,000	$ 1,200.00			$ 9.25	$ 1,500.00			$ 9.88	100.0%	$ 3,450
Total													**$ 143,000**

Appendix C

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Net Plant Targets
($000)

	Electric[1]			
	RY1	RY2	RY3	
Electric Net Plant Targets[2]:				
Plant In Service	1,673,283	1,777,593	1,887,099	
Accumulated Reserve [3]	(449,615)	(469,265)	(493,703)	
Net Plant	1,223,668	1,308,328	1,393,396	
NIBCWIP	22,082	28,267	27,739	
Net Electric Plant Targets	1,245,750	1,336,595	1,421,135	5
Depreciation Expense Targets:				
Transportation Depreciation [4]	2,508	2,679	2,832	
Depreciation Expense [4]	45,292	50,255	54,893	
Electric Depreciation Expense Target	47,800	52,934	57,725	5

	Gas[1]			
	RY1	RY2	RY3	
Gas Net Plant Targets[2]:				
Plant In Service	604,248	667,162	728,482	
Accumulated Reserve [3]	(149,411)	(157,155)	(166,606)	
Net Plant	454,837	510,007	561,876	
NIBCWIP	18,763	16,382	15,969	
Net Gas Plant Targets	473,600	526,389	577,845	5
Depreciation Expense Targets:				
Transportation Depreciation [4]	720	769	813	
Depreciation Expense [4]	13,794	15,570	17,244	
Gas Depreciation Expense Target	14,514	16,339	18,057	5

1 - Electric and Gas amounts include allocation of Common Plant.

2 - Electric and Gas Plant, Reserves and NIBCWIP are from the respective Rate Base amounts shown on Appendix A, Schedules 3 and 4.

3 - Includes Retirement Work-in-Progress.

4 - Electric and Gas Depreciation are from the respective Income Statement amounts shown on Appendix A, Schedules 1 and 2.

5 - Net Plant and Depreciation Targets. Targets may be adjusted for projects associated with Cloud-Based or SaaS solutions, NWA projects or NPA projects. Refer to the JP for further detail of these projects. Refer to Appendix F, Schedule 2 for an illustration of the adjustment required to established targets associated with Cloud-Based or SaaS solutions.

Appendix D

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Example Calculation of Revenue Requirements on Net Plant Targets
($000)

	Electric[1]			Gas[1]		
	RY1	RY2	RY3	RY1	RY2	RY3
Targets[2]:						
Net Plant & NIBCWIP	1,245,750	1,336,595	1,421,135	473,600	526,389	577,845
Depreciation Expense	47,800	52,934	57,725	14,514	16,339	18,057
Actual[4] (For Illustrative Purposes Only):						
Total Net Plant & NIBCWIP	1,252,000	1,338,000	1,418,000	469,000	526,500	586,000
Depreciation Expense	48,000	53,000	57,000	14,500	16,500	18,000
Difference (For Illustrative Purposes Only):						
Total Net Plant & NIBCWIP	6,250	1,405	(3,135)	(4,600)	111	8,155
Depreciation Expense	200	66	(725)	(14)	161	(57)
Determination of Revenue Requirements:						
Return Component:						
Net Plant & NIBCWIP Difference	6,250	1,405	(3,135)	(4,600)	111	8,155
x Pre-tax WACC	7.93%	8.01%	8.10%	7.93%	8.01%	8.10%
Return Component	496	113	(254)	(365)	9	661
Revenue Requirement on Differences:						
Depreciation	200	66	(725)	(14)	161	(57)
Return Component	496	113	(254)	(365)	9	661
Total	696	179	(979)	(379)	170	604
Cumulative Revenue Requirement Impact	696	874	(105)	(379)	(209)	395
Amount Deferred for Customer Benefit - Smaller of Cumulative Amount at End of RY3 or $0[3]			(105)			-

[1] - Electric and Gas amounts include allocation of Common Plant

[2] - See Appendix C

[3] - Negative cumulative amount at the end of RY3 indicates Regulatory Liability due to Customers.

[4] - Actual amounts may be adjusted for projects for which the Company is authorized and defers the revenue requirement effect (return on investment and depreciation) of the project. Refer to the Joint Proposal for details of these projects. This adjustment is required in order to avoid double counting the required deferral due back to customers.

Appendix E
Sheet 1 of 2
Central Hudson Gas & Electric Corporation
Cases 17-E-0459; 17-G-0460

The annual reports called for in item V.A.5 of this Proposal will be comprised of the two spreadsheets in this Appendix, appropriately filled out by the Company to reflect actual and forecasted events for the preceding calendar year.

Major Capital Project Report (Projects over $1.0 Million)

		Project Expenditures ($000)										**Project I/S Date**		
Project Description	**Investment Category**	**Original Estimate**	**Actual to Date**	**2014 and Prior**	**2015**	**2016**	**2017**	**2018**	**2019**	**Future**	**Total**	**Original Estimate**	**Projected**	**Comments**
ELECTRIC PRODUCTION														
ELECTRIC TRANSMISSION														
ELECTRIC SUBSTATION														
DISTRIBUTION IMPROVEMENTS														
COMMON PROGRAM														

Notes:

Appendix E
Sheet 2 of 2
Case 17-E-0459 and Case 17-G-0460

20XX Construction Budget

Budget vs Actual Expenditures
($000)
Major Variation Explanations (Variations +/- 20% and $500k)

Year: 20XX	Month: Dec	Work Order Group: All

Charge Type: Additions

Category	Work Order Group	20XX Original Budget	20XX Actual	20XX Adjusted Budget	Variance	% Budget (Act/Bud)
Additions - Total		**$0**	**$0**	**$0**	**$0**	**0.00%**
Electric - Total		**$0**	**$0**	**$0**	**$0**	**0.00%**
Electric	11 - Electric - Hydro/Gas Turbines	$0	$0	$0	$0	0.00%
Electric	12 - Electric - Transmission	$0	$0	$0	$0	0.00%
Electric	13 - Electric - Substations	$0	$0	$0	$0	0.00%
Electric	14 - Electric - Distrib. New Bus.	$0	$0	$0	$0	0.00%
Electric	15 - Electric - Distribution Improv	$0	$0	$0	$0	0.00%
Electric	16 - Electric - Transformers	$0	$0	$0	$0	0.00%
Electric	17 - Electric - Meters	$0	$0	$0	$0	0.00%
Electric	19 - Electric - Storm Damage	$0	$0	$0	$0	0.00%
Gas - Total		**$0**	**$0**	**$0**	**$0**	**0.00%**
Gas	22 - Gas - Transmission	$0	$0	$0	$0	0.00%
Gas	23 - Gas - Regulator Stations	$0	$0	$0	$0	0.00%
Gas	24 - Gas - Distrib. New Business	$0	$0	$0	$0	0.00%
Gas	25 - Gas - Distribution Improvments	$0	$0	$0	$0	0.00%
Gas	27 - Gas - Meters	$0	$0	$0	$0	0.00%
Common - Total		**$0**	**$0**	**$0**	**$0**	**0.00%**
Common	41 - Common - Land & Structures	$0	$0	$0	$0	0.00%
Common	4210 - General Office Equip.	$0	$0	$0	$0	0.00%
Common	4220 - Software	$0	$0	$0	$0	0.00%
Common	4221 - IT	$0	$0	$0	$0	0.00%
Common	4222 - IT Equipment	$0	$0	$0	$0	0.00%
Common	4230 - EMS Hardware	$0	$0	$0	$0	0.00%
Common	4235 - EMS Software	$0	$0	$0	$0	0.00%
Common	4240 - Security	$0	$0	$0	$0	0.00%
Common	43 - Common - Tools & Work Equip.	$0	$0	$0	$0	0.00%
Common	44 - Common - Communications	$0	$0	$0	$0	0.00%
Common	45 - Common - Transportation	$0	$0	$0	$0	9.94%
Overheads - Total		**$0**	**$0**	**$0**	**$0**	**0.00%**
Overheads	Overheads	$0	$0	$0	$0	0

Major Variation Explanations (Variations +/- 20% and $500k)
Note 1:
Note 2:
Note 3:
Note 4:

Appendix F

Central Hudson Gas & Electric Corporation
Case 17-E-0459 & Case 17-G-0460

Listing of Deferrals

Deferral Item	Page # Ref	Deferral Method	Carrying Charges
Asbestos Litigation	12	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	15	Deferral of depreciation and accretion expense incurred on ARO assets and liabilities.	Not applicable
Carbon Reduction Program	25, 71	Deferral of actual expenses over / under rate allowance during RY1 and RY2, with final cumulative deferral at December 31, 2021 for any under-spending only. Carrying Charges to be applied at December 31, 2021. Refer to JP for further details on additional available funding from EET.	Pre-tax Authorized Rate of Return
Clean Energy Fund (including expired RPS, EEPS and SBC Surcharge)	15,23	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
Energy Efficiency (EET)	24-25, 46-47	Deferral of actual expenditures over / under rate allowance during RY1 and RY2, with final cumulative deferral at December 31, 2021 for any under-spending only. Carrying Charges to be applied at December 31, 2021. Refer to JP for additional details on authorized allocation of amounts to Carbon Reduction.	Pre-tax Authorized Rate of Return
Energy Efficiency (EET) - Exemptions	30,47	Deferral of differences between electric Energy Efficiency exemptions imputed in base rates and actual Energy Efficiency exemptions provided as describoed in Section XIII of the JP.	Pre-tax Authorized Rate of Return
Cloud Based or SaaS solutions implemented	26-27, App F Sch 2	Deferral of the revenue requirement effect (depreciation and return on investment) of any variations resulting from software solutions chosen that require a different accounting treatment than that assumed in the establishment of net plant targets and depreciation. This deferral will be offset by the revenue requirement effect of the actual project cost, which will be adjusted out of net plant targets. See JP for further details.	Pre-tax Authorized Rate of Return
Credit / Debit Card Fees	27, 57-59	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 Revenues	7,21, 35-36	Deferral of delivery revenues associated with providing gas service to Danskammer. Refer to JP for additional details.	Refer to JP for additional details
Deferred Temp Metro Transit Bus Tax Surcharge	12	Deferral actual cost over / under the amount collected through Surcharge.	Not applicable
Deferred Unbilled Revenues	16	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 Vacation Pay Accrual	16	Deferral of vacation accrual recorded.	Not applicable
Director Fees (Included in Miscellaneous General element of expense)	30	The director fees will be subject to deferral if management audit recommendations 4.3 and 4.4 are implemented as recommended by Overland Consulting. Refer to JP for further detail.	Pre-tax Authorized Rate of Return
Earnings Sharing Mechanism	16,34	Earnings shared 50/50 between 9.3% and 9.8%; 80/20 between 9.8% and 10.3% and 90/10 in excess of 10.3%	Pre-tax Authorized Rate of Return
Economic Development	16,42	Expenditures charged against the existing deferred balance (PSC Account 254.70) and in the event the fund balance is exhausted, deferral of expenditures for future recovery from customers.	Not applicable
Energy Storage Projects	28	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	14	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
External Rate Case Expenses	21	Deferral of costs incurred reduced by amount collected in rates with no true-up associated with current rate case expense.	Pre-tax Authorized Rate of Return
FAS 109	12	Deferral of tax on basis differences not provided for elsewhere.	Not applicable
FEMA Grant Microgrid Project	29	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
Gas - Methane Detection Plan/First Responder Training Program	30,53, 64	Expenditures charged against the existing Gas NRA deferred balance (PSC Account 254.37). In the event the fund balance is exhausted, deferral of expenditures for future recovery from customers.	Not applicable
Gas Leak Prone Pipe (PRA) - Miles Above Target	22,54	Deferral of 2bp positive revenue adjustment for each mile in excess of target; capped at maximum 6 miles (12bp) per calendar year.	Not applicable
Gas Leak Prone Pipe (Revenue Requirement) - Cost per Mile Above Target	22,54	Deferral of the revenue requirement effect (depreciation and return on investment) for each mile completed above the annual target of 15 miles premised on capital expenditures capped at the following amounts per mile: 2018 - $1.780 million; 2019 - $1.895; 2020 - $2.010 million; and 2021 - $2.125 million. Refer to JP for additional details.	Pre-tax Authorized Rate of Return
Gas Leak Repair Incentive (PRA) - Type 3 Leaks	27, 51-52	Deferral of 4 basis point incentive for eliminating 20 of 25 type 3 leaks from the leak backlog at the beginning of the calendar year determined to be highest priority.	Not applicable
Governmental, Legislative and Other Regulatory Actions	17-18	Deferral of the revenue requirement effect of new governmental, legislative or other regulatory actions in the aggregate in a rate year subject to a 10 basis point materiality threshold.	Pre-tax Authorized Rate of Return
Long Term Debt - Variable Rate 2014 Series E Bond	13-14	Deferral and amortization of the costs associated with the refinancing of this Bond should it occur during the rate plan.	N/A
Long Term Debt - Variable Rate NYSERDA Series B Bond	13-14	Deferral and amortization of the costs associated with the refinancing of this Bond should it occur during the rate plan.	N/A
Long Term Debt Interest Costs - Existing Variable Rate Debt	13-14	Deferral of interest costs over / under rate allowance	Pre-tax Authorized Rate of Return
Long Term Debt Interest Costs - New Fixed & Variable Issuances	13	Deferral of interest costs over / under rate allowance (RY2-3 only). Refer to JP for details.	Pre-tax Authorized Rate of Return

Appendix F

Central Hudson Gas & Electric Corporation
Case 17-E-0459 & Case 17-G-0460

Listing of Deferrals

Deferral Item	Page # Ref	Deferral Method	Carrying Charges
Low Income Program - Arrears Forgiveness	17,39	Deferral of costs over / under rate allowance for arrears forgiveness component to be phased out during Rate Year 2.	Pre-tax Authorized Rate of Return
Low Income Program - Bill Discount	17, 38-39	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
Low Income Program - Waiver of Reconnection Fee	17,39	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	15, App U	Deferral of costs over / under rate allowance for major storms as defined in Appendix U.	Pre-tax Authorized Rate of Return
Net Lost Revenues - Merchant Function Charge	14, 45-46	Deferral of actual lost revenues over / under amount forecasted in rates due to migration for Non-RDM classes.	Pre-tax Authorized Rate of Return
Net Plant Targets	9-10, 14, App C, App D	Deferral of amounts under Net Plant and Depreciation targets cumulatively as shown in Appendices C and D.	Pre-tax Authorized Rate of Return
Non-Pipes Alternative (NPA) Projects	29, 61-63	Deferral of revenue requirement effect of costs incurred during the term of the Rate Year as specified in JP.	Pre-tax Authorized Rate of Return
Non-Wires Alternative (NWA) Projects	21-22	Deferral of revenue requirement effect of costs as authorized in the Commission's July 15, 2016 Order in Case 14-E-0318.	Pre-tax Authorized Rate of Return
OPEB	14	Deferral of expenses over / under rate allowance	Not applicable
Pension and OPEB reserve carrying charges	29	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	14	Deferral of expenses over / under rate allowance	Not applicable
Property Taxes	14-15	Deferral of 90% of the difference between actual expense and the rate allowance subject to limitations as defined in JP.	Pre-tax Authorized Rate of Return
PSC initiated or Required Management or Operational Audit	14	Deferral of costs incurred.	Pre-tax Authorized Rate of Return
Purchased Electric Costs	15	Deferral of actual costs over / under the amount collected.	Not applicable
Purchased Gas Costs	15	Deferral of actual costs over / under the amount collected.	Not applicable
Research and Development	15	Deferral of costs over / under rate allowance	Not applicable
REV Demonstration Projects	15, 74-75	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 from CenHub	28,75	Deferral of 80% of the Company's share of the revenue earned from sales through the CenHub platform.	Pre-tax Authorized Rate of Return
Incremental costs associated with Case 14-M-0101 and related proceedings/Orders, including consultant services to support the Joint Utility efforts support in the preparation of an updated DSIP.	27	Deferral of the revenue requirement effect over / under the amount included in rates (rate allowance as a component of Consulting & Professional Services and capital projects included in the establishment of net plant targets and depreciation).	Pre-tax Authorized Rate of Return
Revenue Decoupling Mechanism - Electric	18, 42-43, 72-73, App O	Deferral of actual revenues billed over / under targeted revenues. Geothermal rate impact credit to be funded through an expense component of the electric RDM.	Other Customer Capital Rate
Revenue Decoupling Mechanism - Gas	15,43	Deferral of actual revenue per customer over / under the target revenue per customer multiplied by the actual number of customers billed.	Other Customer Capital Rate
Right of Way Maintenance - Transmission	18, 20-21, App F Sch 3	Deferral of actual expenses over / under rate allowance up to $500k per year to be applied against ROW maintenance in subsequent rate years during the term of this agreement. Over expenditures in excess of $500k in any RY will be absorbed by the Company (not recovered from customers). Any under expenditures in excess of $500k in any RY will be deferred for return to customers, not to be applied against ROW maintenance in subsequent rate years. Final cumulative deferral at the end of RY3 for any under-spending only. Carrying Charges to be applied at the end of Rate Year 3.	Pre-tax Authorized Rate of Return
Right of Way Maintenance - Distribution	18-20, App F Sch 3	Deferral of actual expenses over / under rate allowance up to $1M per year to be applied against ROW maintenance in subsequent rate years during the term of this agreement. Over expenditures in excess of $1M in any RY will be absorbed by the Company (not recovered from customers). Any under expenditures in excess of $1M in any RY will be deferred for return to customers, not to be applied against ROW maintenance in subsequent rate years. Final cumulative deferral at the end of Rate Year 3 for any under-spending only. Carrying Charges to be applied at the end of Rate Year 3.	Pre-tax Authorized Rate of Return
Stray Voltage Expenses	15	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Tax Cuts and Jobs Act of 2017 (Tax Reform Act)	26	Deferral of the revenue requirement effect of actual costs or benefits over / under amounts assumed in the development of delivery rates related to Tax Cuts and Jobs Act, including any actions at the State or local levels.	Pre-tax Authorized Rate of Return
Training Center and Primary Control Center	27, 48-49	Deferral of revenue requirement effect of costs incurred during the term of the Rate Year as specified in JP.	Pre-tax Authorized Rate of Return

Appendix F, Schedule 2
CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CASES 17-E-0459 and 17-G-0460
EXAMPLE OF DEFERRAL FOR CLOUD BASED SOFTWARE

Assumptions:

1,000,000	IT Investment - Cloud Based Software
36	Assumed amortization period in rates (3 Years)
333,333	Annual Depreciation In Rates
	Assumed accounting treatment requires expense vs capital treatment
1,000,000	Actual Expense in Year Purchased - Deferred
1,000,000	Adjustment to Net Plant Target

Adjustment to Net Plant Target

		AVERAGE NET UTILITY PLANT					Pre-Tax	Pre-Tax	Book		Cumulative
Month	Adjustment to Net Plant Target	Reserve @ BOM	Book Depreciation	Reserve @ EOM	Average Reserve	Average Net Plant	WACC 7.93%	Return on Investment	Depreciation Expense	Revenue Requirement	Revenue Requirement
1	1,000,000	0	27,778	27,778	13,889	986,111	0.66%	6,517	27,778	34,295	34,295
2			27,778	55,556	41,667	958,333	0.66%	6,333	27,778	34,111	68,406
3			27,778	83,334	69,445	930,555	0.66%	6,149	27,778	33,927	102,333
4			27,778	111,112	97,223	902,777	0.66%	5,966	27,778	33,744	136,077
5			27,778	138,890	125,001	874,999	0.66%	5,782	27,778	33,560	169,637
6			27,778	166,668	152,779	847,221	0.66%	5,599	27,778	33,377	203,014
7			27,778	194,446	180,557	819,443	0.66%	5,415	27,778	33,193	236,207
8			27,778	222,224	208,335	791,665	0.66%	5,232	27,778	33,010	269,217
9			27,778	250,002	236,113	763,887	0.66%	5,048	27,778	32,826	302,043
10			27,778	277,780	263,891	736,109	0.66%	4,864	27,778	32,642	334,685
11			27,778	305,558	291,669	708,331	0.66%	4,681	27,778	32,459	367,144
12			27,778	333,336	319,447	680,553	0.66%	4,497	27,778	32,275	399,419
13			27,778	361,114	347,225	652,775	0.66%	4,314	27,778	32,092	431,511
14			27,778	388,892	375,003	624,997	0.66%	4,130	27,778	31,908	463,419
15			27,778	416,670	402,781	597,219	0.66%	3,947	27,778	31,725	495,144
16			27,778	444,448	430,559	569,441	0.66%	3,763	27,778	31,541	526,685
17			27,778	472,226	458,337	541,663	0.66%	3,579	27,778	31,357	558,042
18			27,778	500,004	486,115	513,885	0.66%	3,396	27,778	31,174	589,216
19			27,778	527,782	513,893	486,107	0.66%	3,212	27,778	30,990	620,206
20			27,778	555,560	541,671	458,329	0.66%	3,029	27,778	30,807	651,013
21			27,778	583,338	569,449	430,551	0.66%	2,845	27,778	30,623	681,636
22			27,778	611,116	597,227	402,773	0.66%	2,662	27,778	30,440	712,076
23			27,778	638,894	625,005	374,995	0.66%	2,478	27,778	30,256	742,332
24			27,778	666,672	652,783	347,217	0.66%	2,295	27,778	30,073	772,405
25			27,778	694,450	680,561	319,439	0.66%	2,111	27,778	29,889	802,294
26			27,778	722,228	708,339	291,661	0.66%	1,927	27,778	29,705	831,999
27			27,778	750,006	736,117	263,883	0.66%	1,744	27,778	29,522	861,521
28			27,778	777,784	763,895	236,105	0.66%	1,560	27,778	29,338	890,859
29			27,778	805,562	791,673	208,327	0.66%	1,377	27,778	29,155	920,014
30			27,778	833,340	819,451	180,549	0.66%	1,193	27,778	28,971	948,985
31			27,778	861,118	847,229	152,771	0.66%	1,010	27,778	28,788	977,773
32			27,778	888,896	875,007	124,993	0.66%	826	27,778	28,604	1,006,377
33			27,778	916,674	902,785	97,215	0.66%	642	27,778	28,420	1,034,797
34			27,778	944,452	930,563	69,437	0.66%	459	27,778	28,237	1,063,034
35			27,778	972,230	958,341	41,659	0.66%	275	27,778	28,053	1,091,087
36			27,770	1,000,000	986,115	13,885	0.66%	92	27,770	27,862	1,118,949
			1,000,000							1,118,949	

Deferral and Related Carrying Charges

					Pre-Tax	Deferred	
Month	Deferred Expense	Amount in Rates	Net Deferred Expense Balance	Net of Tax	WACC 7.93%	Carrying Charges	
1	1,000,000	(34,295)	965,705	713,318	0.66%	2,357	
2	1,000,000	(68,406)	931,594	688,122	0.66%	4,631	
3	1,000,000	(102,333)	897,667	663,062	0.66%	4,465	
4	1,000,000	(136,077)	863,923	638,137	0.66%	4,299	
5	1,000,000	(169,637)	830,363	613,348	0.66%	4,135	
6	1,000,000	(203,014)	796,986	588,694	0.66%	3,972	
7	1,000,000	(236,207)	763,793	564,176	0.66%	3,809	
8	1,000,000	(269,217)	730,783	539,793	0.66%	3,648	
9	1,000,000	(302,043)	697,957	515,546	0.66%	3,487	
10	1,000,000	(334,685)	665,315	491,435	0.66%	3,327	
11	1,000,000	(367,144)	632,856	467,459	0.66%	3,168	
12	1,000,000	(399,419)	600,581	443,619	0.66%	3,010	
13	1,000,000	(431,511)	568,489	419,914	0.66%	2,853	
14	1,000,000	(463,419)	536,581	396,346	0.66%	2,697	
15	1,000,000	(495,144)	504,856	372,912	0.66%	2,542	
16	1,000,000	(526,685)	473,315	349,614	0.66%	2,387	
17	1,000,000	(558,042)	441,958	326,452	0.66%	2,234	
18	1,000,000	(589,216)	410,784	303,426	0.66%	2,081	
19	1,000,000	(620,206)	379,794	280,535	0.66%	1,930	
20	1,000,000	(651,013)	348,987	257,779	0.66%	1,779	
21	1,000,000	(681,636)	318,364	235,160	0.66%	1,629	
22	1,000,000	(712,076)	287,924	212,675	0.66%	1,480	
23	1,000,000	(742,332)	257,668	190,326	0.66%	1,332	
24	1,000,000	(772,405)	227,595	168,113	0.66%	1,184	
25	1,000,000	(802,294)	197,706	146,036	0.66%	1,038	
26	1,000,000	(831,999)	168,001	124,094	0.66%	893	
27	1,000,000	(861,521)	138,479	102,288	0.66%	748	
28	1,000,000	(890,859)	109,141	80,617	0.66%	604	
29	1,000,000	(920,014)	79,986	59,082	0.66%	462	
30	1,000,000	(948,985)	51,015	37,682	0.66%	320	
31	1,000,000	(977,773)	22,227	16,418	0.66%	179	
32	1,000,000	(1,006,377)	(6,377)	(4,710)	0.66%	39	
33	1,000,000	(1,034,797)	(34,797)	(25,703)	0.66%	(100)	
34	1,000,000	(1,063,034)	(63,034)	(46,560)	0.66%	(239)	
35	1,000,000	(1,091,087)	(91,087)	(67,281)	0.66%	(376)	
36	1,000,000	(1,118,949)	(118,949)	(87,862)	0.66%	(513)	
			(118,949)			71,491	(47,458) Net Owed to Customers

Central Hudson Gas & Electric Corporation
Example Calculation of Transmission and Distribution ROW Maintenance Deferral
($000)

	Transmission			Distribution		
	RY1	RY2	RY3	RY1	RY2	RY3
Allowance ($000) Per Appendix A	3,500	2,900	2,614	19,588	19,999	20,419
RY1 Allowance	3,500			19,588		
Actual Spend (For Illustrative Purposes Only)	2,900			21,588		
Over/(Under) Spend	(600)			2,000		
Amount Deferred and rolled from/(to) RY2	(500)			1,000		
Overspend absorbed by Company / (Underspend) returned to customers	(100)			1,000		
RY2 Allowance		2,900			19,999	
Amount Deferred and rolled from/(to) RY1		500			(1,000)	
Revised RY2 Allowance		3,400			18,999	
Actual Spend (For Illustrative Purposes Only)		3,700			17,998	
Over/(Under) Spend on revised target		300			(1,001)	
Amount Deferred and rolled from/(to) RY3		300			(1,000)	
Overspend absorbed by Company / (Underspend) returned to customers		-			(1)	
RY3 Allowance			2,614			20,419
Amount Deferred and rolled from/(to) RY2			(300)			1,000
Revised RY3 Allowance			2,314			21,419
Actual Spend (For Illustrative Purposes Only)			2,400			21,350
Over/(Under) Spend on revised target			86			(69)
Overspend absorbed by Company / (Underspend) returned to customers			86			(69)
CUMULATIVE $ TO RETURN TO CUSTOMER AT END OF RATE YEAR 3			**(100)**			**(70)**
CUMULATIVE $ TO BE ABSORBED BY COMPANY AT END OF RATE YEAR 3			**86**			**1,000**

Appendix G
Sheet 1 of 5
Central Hudson Gas & Electric Corporation
Cases 17-E-0459 and 17-G-0460
Rate Adjustment Mechanism

The Company will implement a Rate Adjustment Mechanism (“RAM”) to refund or recover the net balance of RAM Eligible Deferrals and Carrying Charges, positive revenue adjustments (“PRAs”), unencumbered negative revenue adjustments (“NRAs”) and Costs. For the avoidance of doubt, incentives associated with EAM achievement will not be collected through the RAM. All RAM eligible deferrals and costs shall be the difference between actual costs and the amounts provided for in base rates. All RAM revenues and deferrals are subject to reconciliation.

RAM Eligible Deferrals and Costs include:

(1) carrying charges accrued on deferred balances included on the balance sheet offset (July 1, 2018) in the event that the suspension period is extended;

(2) carrying charges accrued on the balances available for moderation;

(3) carrying charges accrued on over/under recovery of low income bill discounts;

(4) Environmental SIR deferral balances in excess of the three year cumulative rate allowance and carrying charges accrued on deferred Environmental SIR costs incurred in excess of / below amounts collected in rates;

(5) carrying charges accrued associated with deferrals authorized in the REV Proceeding and related proceedings, including NWAs;

(6) carrying charges accrued on deferral balances associated with NPAs;

(7) major storm events charged to the Major Storm Reserve in excess of the three-year cumulative rate allowance and carrying charges accrued on the Major Storm Reserve;

(8) carrying charges accrued on over/under recovery of interest costs on existing Variable Rate Debt;

(9) carrying charges accrued on over/under recovery of interest cost of New Fixed or Variable Issues of Long Term Debt (Rate Years 2 and 3 only;

(10) property tax deferral balances and carrying charges accrued on property tax deferral balances;

(11) carrying charges accrued on deferral balances associated with cloud-based IT solutions as defined under Section [V.B.4.d] of the Joint Proposal;

(12) PRAs and unencumbered NRAs earned or incurred and deferred for future recovery or pass-back for achieving/failing targets or objectives defined;

(13) carrying charges accrued on deferral balances associated with new regulatory or legislative action, including the Tax Cuts & Jobs Act;

(14) revenue requirement effect (depreciation and carrying charges on investment) accrued on LPP replacement incremental to the annual 15 miles funded in base rates; and

(15) carrying charges accrued on deferral balances associated with differences between actual electric Energy Efficiency exemptions and exemptions imputed in base rates.

Recovery Mechanics

The Company shall measure the deferred regulatory asset and liability balances for the items specified as RAM Eligible Deferrals and Costs as of December 31 of each year. The electric and gas RAM balances identified for recovery / return shall be subject to the minimum and maximum amounts shown in the table below and shall be identified in respective RAM Compliance Filings. The RAM for Electric and Gas shall be identified in respective RAM Compliance

Filings submitted on March 31 of each year and shall be implemented in rates on July 1 of each year (beginning July 1, 2019) for collection over the 12 months from July 1 to June 30.

	Electric ($million)		**Gas ($million)**	
	Dollar Threshold		Dollar Threshold	
	Minimum	Maximum	Minimum	Maximum
Rate Year 1	$0.350	$8.800	$0.150	$2.700
Rate Year 2	$0.350	$9.200	$0.150	$2.900
Rate Year 3	$0.350	$9.800	$0.150	$3.100

To the extent the service classification/sub-classification allocation of balances results in a zero factor for a service classification/sub-classification, such allocated balance will be considered an over/under-collection and treated accordingly.

The RAMs for Electric and Gas individually will be determined by netting the RAM Eligible Deferrals. Any net RAM Eligible Deferral value in excess of the specific Electric or Gas limit will remain deferred and will be carried forward to the calculation of the RAM limits in the following year.

RAM Review Process

Upon request of a Signatory to this JP and within 60 days of the RAM filing, the Company will convene an informational meeting in person or via teleconference to review the Company's calculation of the RAM.

In the event that Staff or any Signatory to this JP objects to the calculation of the RAM, Staff or such Signatory shall notify the Company and the parties in writing within 30 calendar days after the RAM Compliance Filing is submitted.

The Company will respond in writing within 30 calendar days addressing the objection. To the extent that Staff or the Signatory believes its concerns were not fully addressed by the Company's response, Staff or such Signatory may submit written comments to the Commission.

In the event of a dispute regarding the calculation of the annual RAM, the RAM will be implemented as described above and any disputed amounts subject to refund will be incorporated in a subsequent reconciliation. The Signatories will use their best efforts to resolve the dispute within 150 calendar days of the Company's response. The Signatories agree to utilize the Commission's dispute resolution process to resolve any contested matters. To the extent the Signatories are unable to resolve any remaining differences, the Signatories agree to present such differences to the Commission for resolution.

The implementation of the RAM shall not limit Staff's right to audit the deferred costs included by the Company in the RAM.

Carrying Costs

During the period the RAM is in effect for those deferrals being specifically collected or returned, carrying costs will be based on the Commission's authorized Other Customer Capital Rate. RAM Eligible Deferral balances not in the RAM tariff due to the annual dollar amount restrictions set forth above will accrue carrying charges as follows:

(1) Net deferral amounts at or under the RAM recovery/return limits will accrue carrying charges at the Other Customer Capital Rate; and

(2) Additional deferral amounts over the annual RAM recovery/return limits will accrue carrying costs at Central Hudson's Pre-Tax Weighted Cost of Capital, applied to the after-tax balance.

Over/under-collections or refund of RAM amounts will be carried forward to subsequent periods and assumed to be the first dollars collected or refunded. Deferred amounts will be allocated to Electric and Gas in accordance with the nature of the underlying item.

Electric Recovery / Refund

The Electric RAM annual recovery/return amounts shall be delivered through a new component of the MISC. It will be allocated to service classes/sub-classes based on annual delivery service revenues. The rates will be developed on per-kWh basis for non-demand billed customers and per-kW basis for demand billed customers.

Gas Recovery / Refund

The Gas RAM annual recovery/return amounts shall be delivered through a new gas surcharge/sur-credit rate to be combined with other new gas surcharges. It will be allocated to service classes, excluding the interruptible service class, based on annual delivery service revenues. The rates will be developed on a per-Ccf basis.

Appendix H

Central Hudson Gas & Electric Corporation
Case Nos. 17-E-0459 & 17-G-0460
Net Deferred Accounts Available For Moderation

The following accounts are subject to offset as of July 1, 2018, with the net deferred regulatory credit available for rate moderation:

Description	Electric	Gas
Rate Case Expenses	X	X
Storm Deferrals - pre-Storm Reserve	X	N/A
Storm Deferrals Sales Tax Adjustment - pre-Storm Reserve	X	N/A
Pension Over/Under Collection	X	X
NYS Capital Base Tax Carrying Charges	X	X
NYS Capital Base Tax	X	X
NYS Income Tax Rate Change	X	N/A
NYS Income Tax Rate Change Carrying Charges	X	N/A
Management Audit Carrying Charges	X	X
Storm Costs Carrying Charges	X	N/A
Storm Costs Sales Tax Adjustment Carrying Charges	X	N/A
Property Taxes Over/Under Collection	X	X
Property Taxes Carrying Charges	X	X
Gas Threat Assessment - Horseheads Order	N/A	X
PSC 18A Assessment Over/Under Collection	X	X
PSC General Assessment Over/Under Collection	X	X
PSC 18A Assessment Carrying Charges	X	X
PSC General Assessment Carrying Charges	X	X
REV Demonstration Projects	X	N/A
REV Demonstration Projects Carrying Charges	X	N/A
Unprotected Income Tax Rate Change Carrying Charges	X	X
Positive Revenue Adjustments	X	X
Bulk Electric System	X	N/A
Bulk Electric System Carrying Charges	X	N/A
Gas Threat Assessment - Horseheads Order Carrying Charges	N/A	X
Major Storm Reserve	X	N/A
Empire Zone Rate Lost Revenues	X	N/A
Empire Zone Rate Lost Revenues Carrying Charges	X	N/A
Energy Efficiency Incentives Carrying Charges	X	X
Revenue Requirement Leak Prone Pipe	N/A	X
Asbestos Litigation Costs	X	N/A
Asbestos Litigation Costs Carrying Charges	X	N/A
Environmental SIR Costs - Carrying Charges	X	X
DSIP Carrying Charges	X	N/A
Pension Reserve Carrying Charges	X	X
DSIP	X	N/A
Research & Development	X	X
NMP2 Costs	X	N/A
NMP2 Costs Carrying Charges	X	N/A
Interest Overcollection	X	X
Interest Overcollection Carrying Charges	X	X
Electric Reliability Incentive	X	N/A
Shared Earnings Carrying Charges	X	N/A
Federal Income Tax Research Credit	X	X
EPOP Overcollection	X	X
Variable Rate Interest Undercollection	X	X
Variable Rate Interest Carrying Charges	X	X
Low Income Program/Waiver of Reconnection Fee	X	X
Low Income Program/Competitive Education Funding	X	X
Low Income Program/Bill Discount	X	X
Low Income Program/Waiver of Reconnection Fee Carrying Charges	X	X
Low Income Program/Bill Discount Carrying Charges	X	X
EPOP Carrying Charges	X	X
Bonus Depreciation	X	X
Bonus Depreciation Carrying Charges	X	X
OPEB Medicare Subsidy Over/Under	X	X
OPEB Over/Under Collection	X	X
OPEB Reserve Carrying Charges	X	X
Competitive Metering Initiative	X	N/A
Competition Education Campaign Costs	X	X
Shared Earnings	X	N/A
Net Plant Depreciation Target Shortfall	X	X
Net Plant Depreciation Target Shortfall Carrying Charges	X	N/A
Cost to Achieve Tax Refunds	X	X
Cost to Achieve Tax Refunds Carrying Charges	X	X
Rate Moderator	X	X
Rate Moderator Carrying Charges	X	X
Stray Voltage Overcollection	X	N/A
Stray Voltage Overcollection Carrying Charges	X	N/A

This listing of accounts is presented without prejudice with respect to any error or omission and the Company or Staff reserves the right to revise this listing, which will be subject to Staff review and approval.

Appendix I

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Revenue Matching Factors

	Rate Year #1	Rate Year #2	Rate Year #3
ELECTRIC:			
Research & Development:			
Rate Allowance ($000)	$2,537	$2,590	$2,644
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	4,886,495	4,842,005	4,780,656
Revenue Matching Factor - $/kWh	$0.000519	$0.000535	$0.000553
Pension Plan:			
Rate Allowance ($000)	$8,485	$1,822	$1,448
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	4,886,495	4,842,005	4,780,656
Revenue Matching Factor - $/kWh	$0.001736	$0.000376	$0.000303
OPEB - Including Medicare Subsidy			
Rate Allowance ($000)	($6,306)	($5,585)	($4,596)
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	4,886,495	4,842,005	4,780,656
Revenue Matching Factor - $/kWh	($0.001290)	($0.001153)	($0.000961)

	Rate Year #1	Rate Year #2	Rate Year #3
GAS:			
Research & Development:			
Rate Allowance ($000)	$603	$616	$629
SC 1, 2, 6, 12 & 13 Sales (Mcf)	12,715,109	12,878,550	13,021,756
Revenue Matching Factor - $/Mcf	$0.047424	$0.047831	$0.048304
Pension Plan:			
Rate Allowance ($000)	$2,418	$742	$639
SC 1, 2, 6, 12 & 13 Sales (Mcf)	12,715,109	12,878,550	13,021,756
Revenue Matching Factor - $/Mcf	$0.190167	$0.057615	$0.049072
OPEB - Including Medicare Subsidy			
Rate Allowance ($000)	($1,532)	($1,354)	($1,109)
SC 1, 2, 6, 12 & 13 Sales (Mcf)	12,715,109	12,878,550	13,021,756
Revenue Matching Factor - $/Mcf	($0.120487)	($0.105136)	($0.085165)

Appendix J, Schedule 1

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Capital Structure and Allowed Rate of Return
($000)

Rate Year 1:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 726,179	51.5%	4.30%	2.21%	2.21%
Customer Deposits	7,639	0.5%	1.05%	0.01%	0.01%
Common Equity	677,649	48.0%	8.80%	4.22%	5.71%
	$ 1,411,467	100.0%		6.44%	7.93%

Rate Year 2:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 783,536	50.5%	4.30%	2.17%	2.17%
Customer Deposits	7,639	0.5%	1.05%	0.01%	0.01%
Common Equity	759,084	49.0%	8.80%	4.31%	5.83%
	$ 1,550,259	100.0%		6.49%	8.01%

Rate Year 3:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 830,867	49.5%	4.30%	2.13%	2.13%
Customer Deposits	7,639	0.5%	1.05%	0.01%	0.01%
Common Equity	838,103	50.0%	8.80%	4.40%	5.96%
	$ 1,676,609	100.0%		6.54%	8.10%

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST
FOR THE TWELVE MONTHS ENDING JUNE 30, 2019
($000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 06/30/2018 (3)	Charges During Rate Year (4)	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt							
Outstanding Issues							
1999 Series B Variable	July 1, 2034	1.37	33,700	-	12	33,700	460
2004 Series E @ 5.05%	November 4, 2019	5.05	27,000	-	12	27,000	1,364
2005 Series E @ 5.84%	December 5, 2035	5.84	24,000	-	12	24,000	1,402
2006 Series E @ 5.76%	November 17, 2031	5.76	27,000	-	12	27,000	1,555
2007 Series F @ 5.80%	March 23, 2037	5.80	33,000	-	12	33,000	1,915
2009 Series F @ 5.80%	November 1, 2039	5.80	24,000	-	12	24,000	1,392
2010 Series G @ 4.15%	April 1, 2021	4.15	44,150	-	12	44,150	1,832
2010 Series G @ 5.716%	April 1, 2041	5.72	30,000	-	12	30,000	1,715
2011 Series G @ 3.378%	April 1, 2022	3.38	23,400	-	12	23,400	790
2011 Series G @ 4.707%	April 1, 2042	4.71	10,000	-	12	10,000	471
2012 Series G @ 4.776%	April 1, 2042	4.78	48,000	-	12	48,000	2,292
2012 Series G @ 4.065%	October 1, 2042	4.07	24,000	-	12	24,000	976
2010 Series A @ 4.30%	September 21, 2020	4.30	16,000	-	12	16,000	688
2010 Series B @ 5.64%	September 21, 2040	5.64	24,000	-	12	24,000	1,354
2013 Series C @ 2.45%	November 1, 2018	2.45	30,000	(30,000)	8	20,000	490
2013 Series D @ 4.09%	December 2, 2028	4.09	16,700	-	12	16,700	683
2014 Series E Variable	March 26, 2024	2.30	30,000	-	12	30,000	689
2015 Series F @ 2.98%	March 31, 2025	2.98	20,000	-	12	20,000	596
2016 Series G @ 2.16%	September 21, 2020	2.16	24,000	-	12	24,000	518
2016 Series H @ 2.56%	October 28, 2026	2.56	10,000	-	12	10,000	256
2016 Series I @ 3.63%	October 28, 2046	3.63	20,000	-	12	20,000	726
2017 Series J @4.05%	August 31, 2047	4.05	30,000	-	12	30,000	1,215
2017 Series K @4.2%	August 31, 2057	4.20	30,000	-	12	30,000	1,260
2018 New Issuance	April 30, 2038	4.10	20,000	-	12	20,000	820
2018 New Issuance	July 1, 2038	4.10	-	74,229	12	74,229	3,043
2018 New Issuance	October 1, 2038	4.10	-	25,000	9	18,750	769
2018 New Issuance	December 1, 2038	4.10	-	33,000	7	19,250	789
2019 New Issuance	June 1, 2038	4.10	-	60,000	1	5,000	205
Average Long Term Debt Outstanding			618,950	162,229		$ 726,179	
Interest Charges for the Rate Year							$ 30,265
Plus: Amortization of Debt Discount and Expense							925
Less: Amortization of Premium on Debt							-
Total Cost of Debt							
Amount							$ 31,191
% of Average Long Term Debt Outstanding							4.30%

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST
FOR THE TWELVE MONTHS ENDING JUNE 30, 2020
($000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 06/30/2019 (3)	Charges During Rate Year (4)	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt							
Outstanding Issues							
1999 Series B Variable	July 1, 2034	1.37	33,700	-	12	33,700	460
2004 Series E @ 5.05%	November 4, 2019	5.05	27,000	(27,000)	4	9,000	455
2005 Series E @ 5.84%	December 5, 2035	5.84	24,000	-	12	24,000	1,402
2006 Series E @ 5.76%	November 17, 2031	5.76	27,000	-	12	27,000	1,555
2007 Series F @ 5.80%	March 23, 2037	5.80	33,000	-	12	33,000	1,915
2009 Series F @ 5.80%	November 1, 2039	5.80	24,000	-	12	24,000	1,392
2010 Series G @ 4.15%	April 1, 2021	4.15	44,150	-	12	44,150	1,832
2010 Series G @ 5.716%	April 1, 2041	5.72	30,000	-	12	30,000	1,715
2011 Series G @ 3.378%	April 1, 2022	3.38	23,400	-	12	23,400	790
2011 Series G @ 4.707%	April 1, 2042	4.71	10,000	-	12	10,000	471
2012 Series G @ 4.776%	April 1, 2042	4.78	48,000	-	12	48,000	2,292
2012 Series G @ 4.065%	October 1, 2042	4.07	24,000	-	12	24,000	976
2010 Series A @ 4.30%	September 21, 2020	4.30	16,000	-	12	16,000	688
2010 Series B @ 5.64%	September 21, 2040	5.64	24,000	-	12	24,000	1,354
2013 Series D @ 4.09%	December 2, 2028	4.09	16,700	-	12	16,700	683
2014 Series E Variable	March 26, 2024	2.30	30,000	-	12	30,000	689
2015 Series F @ 2.98%	March 31, 2025	2.98	20,000	-	12	20,000	596
2016 Series G @ 2.16%	September 21, 2020	2.16	24,000	-	12	24,000	518
2016 Series H @ 2.56%	October 28, 2026	2.56	10,000	-	12	10,000	256
2016 Series I @ 3.63%	October 28, 2046	3.63	20,000	-	12	20,000	726
2017 Series J @4.05%	August 31, 2047	4.05	30,000	-	12	30,000	1,215
2017 Series K @4.2%	August 31, 2057	4.20	30,000	-	12	30,000	1,260
2018 New Issuance	April 30, 2038	4.10	20,000	-	12	20,000	820
2018 New Issuance	July 1, 2038	4.10	74,229	-	12	74,229	3,043
2018 New Issuance	October 1, 2038	4.10	25,000	-	12	25,000	1,025
2018 New Issuance	December 1, 2038	4.10	33,000	-	12	33,000	1,353
2019 New Issuance	June 1, 2038	4.10	60,000	-	12	60,000	2,460
2019 New Issuance	December 1, 2039	4.10	-	21,183	7	12,357	507
2020 New Issuance	May 15, 2040	4.10	-	64,000	2	8,000	328
Average Long Term Debt Outstanding			781,179	58,183		$ 783,536	
Interest Charges for the Rate Year							$ 32,776
Plus: Amortization of Debt Discount and Expense							929
Less: Amortization of Premium on Debt							-
Total Cost of Debt							
Amount							$ 33,705
% of Average Long Term Debt Outstanding							4.30%

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST
FOR THE TWELVE MONTHS ENDING JUNE 30, 2021
($000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 06/30/2020 (3)	Charges During Rate Year (4)	Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt							
Outstanding Issues							
1999 Series B Variable	July 1, 2034	1.37	33,700	-	12	33,700	460
2005 Series E @ 5.84%	December 5, 2035	5.84	24,000	-	12	24,000	1,402
2006 Series E @ 5.76%	November 17, 2031	5.76	27,000	-	12	27,000	1,555
2007 Series F @ 5.80%	March 23, 2037	5.80	33,000	-	12	33,000	1,915
2009 Series F @ 5.80%	November 1, 2039	5.80	24,000	-	12	24,000	1,392
2010 Series G @ 4.15%	April 1, 2021	4.15	44,150	-	12	44,150	1,832
2010 Series G @ 5.716%	April 1, 2041	5.72	30,000	-	12	30,000	1,715
2011 Series G @ 3.378%	April 1, 2022	3.38	23,400	-	12	23,400	790
2011 Series G @ 4.707%	April 1, 2042	4.71	10,000	-	12	10,000	471
2012 Series G @ 4.776%	April 1, 2042	4.78	48,000	-	12	48,000	2,292
2012 Series G @ 4.065%	October 1, 2042	4.07	24,000	-	12	24,000	976
2010 Series A @ 4.30%	September 21, 2020	4.30	16,000	(16,000)	3	4,000	172
2010 Series B @ 5.64%	September 21, 2040	5.64	24,000	-	12	24,000	1,354
2013 Series D @ 4.09%	December 2, 2028	4.09	16,700	-	12	16,700	683
2014 Series E Variable	March 26, 2024	2.30	30,000	-	12	30,000	689
2015 Series F @ 2.98%	March 31, 2025	2.98	20,000	-	12	20,000	596
2016 Series G @ 2.16%	September 21, 2020	2.16	24,000	(24,000)	3	6,000	130
2016 Series H @ 2.56%	October 28, 2026	2.56	10,000	-	12	10,000	256
2016 Series I @ 3.63%	October 28, 2046	3.63	20,000	-	12	20,000	726
2017 Series J @4.05%	August 31, 2047	4.05	30,000	-	12	30,000	1,215
2017 Series K @4.2%	August 31, 2057	4.20	30,000	-	12	30,000	1,260
2018 New Issuance	April 30, 2038	4.10	20,000	-	12	20,000	820
2018 New Issuance	July 1, 2038	4.10	74,229	-	12	74,229	3,043
2018 New Issuance	October 1, 2038	4.10	25,000	-	12	25,000	1,025
2018 New Issuance	December 1, 2038	4.10	33,000	-	12	33,000	1,353
2019 New Issuance	June 1, 2038	4.10	60,000	-	12	60,000	2,460
2019 New Issuance	December 1, 2039	4.10	21,183	-	12	21,183	869
2020 New Issuance	May 15, 2040	4.10	64,000	-	12	64,000	2,624
2020 New Issuance	December 1, 2040	4.10	-	29,008	7	16,921	694
2021 New Issuance	June 1, 2041	4.10	-	55,000	1	4,583	188
Average Long Term Debt Outstanding			839,362	44,008		$ 830,867	
Interest Charges for the Rate Year							$ 34,956
Plus: Amortization of Debt Discount and Expense							812
Less: Amortization of Premium on Debt							-
Total Cost of Debt							
Amount							$ 35,768
% of Average Long Term Debt Outstanding							4.30%

Appendix J, Schedule 3

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric and Gas Basis Point Values

Basis Point Values:	Electric		
	RY1	**RY2**	**RY3**
Rate Base ($000)	$999,482	$1,080,768	$1,160,578
x Equity Ratio	48%	49%	50%
Equity component of Rate Base ($000)	$479,751	$529,577	$580,289
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$48,000	$53,000	$58,000
Pre-tax value of 1 BP - whole dollars	$65,000	$71,800	$78,500

Basis Point Values:	Gas		
	RY1	**RY2**	**RY3**
Rate Base ($000)	$368,521	$413,857	$459,155
x Equity Ratio	48%	49%	50%
Equity component of Rate Base ($000)	$176,890	$202,790	$229,577
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$17,700	$20,300	$23,000
Pre-tax value of 1 BP - whole dollars	$24,000	$27,500	$31,100

Appendix K Sheet 1 of 20
Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Sales (MWh) by Service Classification

		Twelve Months Ended June 30, 2019	Twelve Months Ended June 30, 2020	Twelve Months Ended June 30, 2021
Service Classification No. 1				
	Heating	305,747	305,058	304,182
	EEPS Lost MWh	(8,436)	(13,502)	(18,568)
	Nonheating	1,710,250	1,729,202	1,745,524
	EEPS Lost MWh	(44,289)	(70,884)	(97,480)
	PV Lost MWh	(22,260)	(36,560)	(52,961)
	Unbilled	-	-	-
		1,941,012	1,913,313	1,880,697
Service Classification No. 2				
	Nondemand	163,462	164,405	164,956
	EEPS Lost MWh	(4,227)	(6,620)	(9,013)
	PV Lost MWh	(2,233)	-	-
	Primary	220,720	220,799	220,495
	EEPS Lost MWh	(5,466)	(8,562)	(11,658)
	Secondary	1,424,816	1,431,143	1,434,288
	EEPS Lost MWh	(35,028)	(54,907)	(74,786)
	PV Lost MWh	(4,240)	(9,073)	(11,009)
	Unbilled	-	-	-
		1,757,805	1,737,184	1,713,272
Service Classification No. 3				
		278,623	278,930	278,744
	EEPS Lost MWh	(6,864)	(10,755)	(14,646)
		271,759	268,176	264,098
Service Classification No. 5		12,333	12,310	12,299
Service Classification No. 6		19,030	19,030	19,030
Service Classification No. 8		17,260	16,240	15,560
Service Classification No. 9		2,370	2,286	2,208
Service Classification No. 13				
	Transmission	711,174	711,174	711,174
	Substation	153,752	162,292	162,318
		864,926	873,466	873,492
Interdepartmental		1,040	1,040	1,040
Total Own Territory		4,887,535	4,843,045	4,781,696

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Base Delivery Revenues by Service Classification

		Twelve Months Ended June 30, 2019	Twelve Months Ended June 30, 2020	Twelve Months Ended June 30, 2021
Service Classification No. 1				
	Heating	$ 30,672,690	$ 32,217,260	$ 34,240,210
	Nonheating	$ 190,660,450	$ 199,316,750	$ 210,872,990
	Unbilled	$ -	$ -	$ -
		$ 221,333,140	$ 231,534,010	$ 245,113,200
Service Classification No. 2				
	Nondemand	$ 18,594,270	$ 19,788,060	$ 21,210,040
	Primary	$ 5,905,466	$ 6,056,614	$ 6,264,735
	Secondary	$ 65,227,515	$ 67,939,200	$ 71,761,369
	Unbilled	$ -	$ -	$ -
		$ 89,727,251	$ 93,783,874	$ 99,236,144
Service Classification No. 3		$ 7,326,638	$ 7,528,433	$ 7,793,850
Service Classification No. 5		$ 1,871,453	$ 1,993,632	$ 2,178,242
Service Classification No. 6		$ 1,392,510	$ 1,449,460	$ 1,525,350
Service Classification No. 8		$ 5,250,750	$ 5,467,696	$ 5,852,351
Service Classification No. 9		$ 232,630	$ 236,280	$ 242,350
Service Classification No. 13				
	Transmission	$ 5,865,700	$ 6,845,444	$ 8,821,486
	Substation	$ 2,214,495	$ 2,610,092	$ 2,822,134
		$ 8,080,195	$ 9,455,536	$ 11,643,620
Interdepartmental		$ 11,130	$ 11,130	$ 11,130
Total Own Territory		$ 335,225,697	$ 351,460,051	$ 373,596,237

Appendix K Sheet 3 of 20

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Customers by Service Classification

	Twelve Months Ended June 30, 2019	Twelve Months Ended June 30, 2020	Twelve Months Ended June 30, 2021
Service Classification No. 1			
Heating	26,766	26,837	26,905
Nonheating	231,648	233,072	234,231
Unbilled	-	-	-
	258,415	259,908	261,136
Service Classification No. 2			
Nondemand	29,713	29,763	29,766
Primary	156	156	156
Secondary	11,704	11,702	11,687
Unbilled	-	-	-
	41,573	41,622	41,608
Service Classification No. 3	31	31	31
Service Classification No. 5	4,008	3,962	3,917
Service Classification No. 6	1,000	1,000	1,000
Service Classification No. 8	210	210	210
Service Classification No. 9	198	191	184
Service Classification No. 13			
Transmission	8	8	8
Substation	5	5	5
	13	13	13
Interdepartmental	1	1	1
Total Own Territory	305,448	306,938	308,101

Appendix K Sheet 4 of 20

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Demand Determinants by Service Classification

	Twelve Months Ended June 30, 2019	Twelve Months Ended June 30, 2020	Twelve Months Ended June 30, 2021
Service Classification No. 2			
Primary kW	571,860	572,063	571,278
EEPS Lost kW	(14,152)	(22,175)	(30,197)
Secondary kW	4,488,191	4,508,135	4,518,048
EEPS Lost kW	(110,298)	(172,920)	(235,541)
PV Lost kW	(13,499)	(28,895)	(35,057)
	4,922,102	4,856,209	4,788,530
Service Classification No. 3 kW	617,679	618,355	617,940
EEPS Lost kW	(15,219)	(23,843)	(32,468)
	602,460	594,512	585,472
Service Classification No. 13			
Transmission kw	1,175,412	1,175,412	1,175,412
Substation kW	220,025	228,572	228,597
	1,395,437	1,403,984	1,404,009
Total kW	6,919,999	6,854,705	6,778,011
Service Classification No. 3 RkVa	108,971	109,089	109,014
EEPS Lost RkVa	(2,676)	(4,200)	(5,724)
	106,295	104,890	103,290
Service Classification No. 13 RkVa			
Transmission RkVa	75,770	75,770	75,770
Substation RkVa	50,190	55,540	55,550
	125,960	131,310	131,320
Total RkVa	232,255	236,200	234,610

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Sales (MWh) by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2019)

	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	Total
Service Classification No. 1													
Heating	16,512	18,352	18,771	17,968	20,599	31,031	40,925	40,643	39,858	25,975	17,727	17,386	305,747
EEPS Lost MWh	(622)	(734)	(733)	(695)	(615)	(721)	(825)	(812)	(755)	(667)	(597)	(661)	(8,436)
Nonheating	138,344	165,151	164,548	142,514	121,674	136,046	159,098	155,931	143,095	127,621	120,587	135,641	1,710,250
EEPS Lost MWh	(3,266)	(3,853)	(3,847)	(3,646)	(3,229)	(3,787)	(4,330)	(4,263)	(3,965)	(3,500)	(3,135)	(3,468)	(44,289)
PV Lost MWh	(1,960)	(1,788)	(1,580)	(1,505)	(1,236)	(1,116)	(782)	(1,231)	(2,364)	(2,697)	(2,818)	(3,184)	(22,260)
	149,008	177,129	177,159	154,636	137,193	161,453	194,086	190,268	175,869	146,732	131,765	145,714	1,941,012
Service Classification No. 2													
Nondemand	12,317	14,178	13,553	12,799	11,771	14,034	15,473	16,175	14,462	14,096	12,327	12,277	163,462
EEPS Lost MWh	(328)	(365)	(341)	(331)	(310)	(361)	(409)	(413)	(373)	(348)	(310)	(339)	(4,227)
PV Lost MWh	(213)	(192)	(167)	(157)	(127)	(114)	(79)	(122)	(232)	(261)	(269)	(300)	(2,233)
Primary	19,024	19,873	18,811	18,060	17,443	18,008	18,589	18,116	17,976	17,869	17,615	19,336	220,720
EEPS Lost MWh	(447)	(466)	(440)	(453)	(441)	(450)	(475)	(459)	(453)	(454)	(445)	(483)	(5,466)
Secondary	130,477	134,042	132,913	112,965	106,958	114,031	121,279	119,105	113,474	110,388	107,454	121,730	1,424,816
EEPS Lost MWh	(3,038)	(3,131)	(3,114)	(2,818)	(2,669)	(2,851)	(3,033)	(3,002)	(2,859)	(2,773)	(2,700)	(3,040)	(35,028)
PV Lost MWh	(404)	(364)	(318)	(299)	(242)	(216)	(149)	(232)	(440)	(496)	(511)	(570)	(4,240)
	157,388	163,575	160,897	139,766	132,382	142,081	151,196	149,168	141,555	138,022	133,161	148,612	1,757,805
Service Classification No. 3	25,133	25,528	24,482	22,892	22,367	23,552	24,114	21,139	22,007	21,249	22,253	23,907	278,623
EEPS Lost MWh	(588)	(597)	(571)	(571)	(564)	(586)	(611)	(533)	(551)	(539)	(560)	(594)	(6,864)
	24,545	24,931	23,911	22,321	21,803	22,966	23,503	20,606	21,456	20,710	21,693	23,313	271,759
Service Classification No. 5	802	896	989	1,144	1,233	1,358	1,293	1,078	1,046	924	830	739	12,333
Service Classification No. 6													
Heating	670	540	530	460	520	910	640	1,080	760	890	420	590	8,010
Nonheating	1,500	1,110	1,080	780	730	870	880	910	960	750	720	730	11,020
	2,170	1,650	1,610	1,240	1,250	1,780	1,520	1,990	1,720	1,640	1,140	1,320	19,030
Service Classification No. 8	1,160	1,300	1,430	1,660	1,790	1,970	1,740	1,450	1,410	1,240	1,120	990	17,260
Service Classification No. 9	200	200	200	198	198	197	203	197	197	191	195	194	2,370
Service Classification No. 13													
Transmission	64,732	65,304	60,558	62,014	56,054	54,160	54,494	52,590	59,470	59,400	61,172	61,226	711,174
Substation	15,136	15,290	11,000	10,850	12,632	11,918	12,868	12,162	12,728	12,252	13,444	13,472	153,752
	79,868	80,594	71,558	72,864	68,686	66,078	67,362	64,752	72,198	71,652	74,616	74,698	864,926
Interdepartmental	90	100	90	90	80	80	90	90	80	80	80	90	1,040
Total	415,231	450,376	437,844	393,919	364,615	397,963	440,994	429,600	415,531	381,192	364,600	395,670	4,887,535

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Base Delivery Revenues (Excluding Revenue Tax) by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2019)

	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	Total
Service Classification No. 1													
Heating	$ 1,840,830	$ 1,978,610	$ 2,013,830	$ 1,950,410	$ 2,171,000	$ 3,001,340	$ 3,790,780	$ 3,752,600	$ 3,726,190	$ 2,598,170	$ 1,941,480	$ 1,907,450	$ 30,672,690
Nonheating	$ 15,555,520	$ 17,691,340	$ 17,655,970	$ 15,910,300	$ 14,278,100	$ 15,425,640	$ 17,264,320	$ 16,860,910	$ 16,009,330	$ 14,646,970	$ 14,098,680	$ 15,263,370	$ 190,660,450
Unbilled	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 17,396,350	$ 19,669,950	$ 19,669,800	$ 17,860,710	$ 16,449,100	$ 18,426,980	$ 21,055,100	$ 20,613,510	$ 19,735,520	$ 17,245,140	$ 16,040,160	$ 17,170,820	$ 221,333,140
Service Classification No. 2													
Nondemand	$ 1,471,260	$ 1,588,960	$ 1,528,110	$ 1,526,520	$ 1,446,740	$ 1,585,580	$ 1,620,320	$ 1,670,160	$ 1,587,100	$ 1,585,120	$ 1,475,570	$ 1,508,830	$ 18,594,270
Primary	$ 549,645	$ 513,525	$ 513,275	$ 484,135	$ 473,135	$ 489,401	$ 450,760	$ 456,380	$ 454,210	$ 486,730	$ 485,650	$ 528,920	$ 5,905,466
Secondary	$ 6,114,409	$ 5,903,810	$ 5,998,470	$ 5,422,091	$ 5,183,580	$ 5,171,788	$ 5,160,790	$ 5,065,260	$ 5,012,010	$ 5,142,540	$ 5,208,290	$ 5,762,340	$ 65,227,515
Unbilled	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 8,135,314	$ 8,006,295	$ 8,039,855	$ 7,432,746	$ 7,103,455	$ 7,246,769	$ 7,231,870	$ 7,191,800	$ 7,053,320	$ 7,214,390	$ 7,169,510	$ 7,800,090	$ 89,727,251
Service Classification No. 3	$ 646,420	$ 620,430	$ 681,150	$ 604,510	$ 622,400	$ 650,620	$ 599,660	$ 535,890	$ 542,850	$ 566,240	$ 615,600	$ 643,910	$ 7,326,638
Service Classification No. 5	$ 153,262	$ 154,382	$ 155,492	$ 157,342	$ 158,412	$ 159,902	$ 159,122	$ 156,552	$ 156,172	$ 154,712	$ 153,592	$ 152,512	$ 1,871,453
Service Classification No. 6	$ 149,710	$ 120,000	$ 117,190	$ 96,220	$ 96,310	$ 127,560	$ 111,980	$ 139,730	$ 123,600	$ 119,430	$ 89,930	$ 100,850	$ 1,392,510
Service Classification No. 8	$ 437,437	$ 437,500	$ 437,559	$ 437,662	$ 437,721	$ 437,802	$ 437,698	$ 437,568	$ 437,550	$ 437,473	$ 437,419	$ 437,361	$ 5,250,750
Service Classification No. 9	$ 19,580	$ 19,540	$ 19,510	$ 19,470	$ 19,430	$ 19,390	$ 19,400	$ 19,340	$ 19,310	$ 19,250	$ 19,220	$ 19,190	$ 232,630
Service Classification No. 13													
Transmission	$ 535,640	$ 562,210	$ 536,290	$ 558,140	$ 490,950	$ 474,800	$ 450,090	$ 457,350	$ 512,350	$ 502,150	$ 518,750	$ 518,570	$ 5,865,700
Substation	$ 218,070	$ 217,070	$ 172,830	$ 176,670	$ 175,270	$ 181,550	$ 213,240	$ 192,760	$ 194,590	$ 178,780	$ 209,310	$ 198,740	$ 2,214,495
	$ 753,710	$ 779,280	$ 709,120	$ 734,810	$ 666,220	$ 656,350	$ 663,330	$ 650,110	$ 706,940	$ 680,930	$ 728,060	$ 717,310	$ 8,080,195
Interdepartmental	$ 960	$ 1,070	$ 960	$ 960	$ 860	$ 860	$ 960	$ 960	$ 860	$ 860	$ 860	$ 960	$ 11,130
Total Base Revenue	$ 27,692,743	$ 29,808,446	$ 29,830,636	$ 27,344,430	$ 25,553,908	$ 27,726,233	$ 30,279,120	$ 29,745,460	$ 28,776,122	$ 26,438,425	$ 25,254,351	$ 27,043,003	$ 335,225,697
Total Base Revenue Excluding Unbilled	$ 27,692,743	$ 29,808,446	$ 29,830,636	$ 27,344,430	$ 25,553,908	$ 27,726,233	$ 30,279,120	$ 29,745,460	$ 28,776,122	$ 26,438,425	$ 25,254,351	$ 27,043,003	$ 335,225,697

Appendix K Sheet 7 of 20

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Customers by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2019)

	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	Average
Service Classification No. 1													
Heating	26,762	26,700	26,767	26,678	26,795	26,763	26,834	26,048	27,581	26,731	26,803	26,733	26,766
Nonheating	230,579	231,138	230,949	231,208	230,720	231,964	231,978	226,368	238,208	232,132	232,042	232,493	231,648
	257,341	257,838	257,716	257,886	257,515	258,727	258,812	252,416	265,789	258,863	258,845	259,226	258,415
Service Classification No. 2													
Nondemand	29,137	30,177	29,099	30,099	29,003	30,160	29,206	29,827	29,782	30,248	29,312	30,508	29,713
Primary	155	155	155	155	155	151	156	153	153	161	160	163	156
Secondary	11,703	11,676	11,722	11,687	11,630	11,686	11,607	11,408	11,988	11,759	11,805	11,775	11,704
	40,995	42,008	40,976	41,941	40,788	41,997	40,969	41,388	41,923	42,168	41,277	42,446	41,573
Service Classification No. 3	31	32	32	31	31	31	31	30	31	32	32	32	31
Service Classification No. 5	4,025	4,006	4,043	4,044	4,017	4,048	3,934	4,018	3,995	4,005	3,925	4,034	4,008
Service Classification No. 6													
Heating	320	370	320	370	320	370	320	370	320	370	320	370	345
Nonheating	670	640	670	640	670	640	670	640	670	640	670	640	655
Service Classification No. 6	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	1,000
Service Classification No. 8	210	210	210	210	210	210	210	210	210	210	210	210	210
Service Classification No. 9	200	200	200	198	198	197	203	197	197	191	195	194	198
Service Classification No. 13													
Transmission	8	8	8	8	8	8	8	8	8	8	8	8	8
Substation	5	5	5	5	5	5	5	5	5	5	5	5	5
	13	13	13	13	13	13	13	13	13	13	13	13	13
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	303,806	305,318	304,181	305,334	303,763	306,234	305,163	299,283	313,149	306,493	305,488	307,166	305,448

Appendix K Sheet 8 of 20

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Demand Determinants by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2019)

	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	Total
Service Classification No. 2													
Primary kW	54,357	49,683	50,163	46,909	45,903	48,021	43,230	44,185	43,844	47,026	46,976	51,563	571,860
EEPS Lost kW	(1,278)	(1,165)	(1,173)	(1,176)	(1,161)	(1,201)	(1,104)	(1,120)	(1,105)	(1,196)	(1,187)	(1,287)	(14,152)
Secondary kW	434,923	412,437	421,946	376,550	356,527	350,865	346,511	340,300	333,747	350,438	358,180	405,767	4,488,191
EEPS Lost kW	(10,128)	(9,634)	(9,887)	(9,393)	(8,898)	(8,773)	(8,666)	(8,577)	(8,409)	(8,802)	(8,999)	(10,133)	(110,298)
PV Lost kW	(1,346)	(1,119)	(1,008)	(995)	(807)	(664)	(426)	(663)	(1,294)	(1,574)	(1,703)	(1,900)	(13,499)
	476,528	450,202	460,041	411,895	391,563	388,249	379,546	374,126	366,783	385,893	393,266	444,010	4,922,102
Service Classification No. 3 kW	54,637	52,098	57,605	50,871	52,628	55,416	50,766	44,977	45,375	47,220	51,751	54,334	617,679
EEPS Lost kW	(1,278)	(1,218)	(1,344)	(1,269)	(1,327)	(1,380)	(1,286)	(1,133)	(1,136)	(1,197)	(1,303)	(1,349)	(15,219)
	53,359	50,880	56,261	49,602	51,301	54,037	49,481	43,843	44,240	46,023	50,448	52,985	602,460
Service Classification No. 13													
Transmission kW	103,640	109,304	103,644	107,548	93,846	90,342	85,255	87,258	98,258	96,318	100,062	99,937	1,175,412
Substation kW	20,830	20,731	16,143	16,567	16,417	17,085	20,109	18,223	18,400	16,731	19,963	18,826	220,025
	124,470	130,035	119,787	124,115	110,263	107,427	105,364	105,481	116,658	113,049	120,025	118,763	1,395,437
Total kW	654,357	631,117	636,089	585,612	553,127	549,712	534,390	523,450	527,681	544,965	563,740	615,758	6,919,999
Service Classification No. 3 RkVa	10,927	10,420	12,385	10,174	9,210	6,927	5,838	5,622	6,806	9,444	10,350	10,867	108,971
EEPS Lost RkVa	(256)	(244)	(289)	(254)	(232)	(172)	(148)	(142)	(170)	(239)	(261)	(270)	(2,676)
	10,672	10,176	12,096	9,920	8,978	6,755	5,690	5,480	6,636	9,205	10,090	10,597	106,295
Service Classification No. 13													
Transmission RkVa	5,810	6,300	6,570	11,170	6,480	6,530	5,070	2,680	7,710	6,220	5,370	5,860	75,770
Substation RkVa	5,290	5,190	3,020	2,930	2,900	3,030	7,510	3,860	4,080	3,640	4,400	4,340	50,190
	11,100	11,490	9,590	14,100	9,380	9,560	12,580	6,540	11,790	9,860	9,770	10,200	125,960
Total RkVa	21,772	21,666	21,686	24,020	18,358	16,315	18,270	12,020	18,426	19,065	19,860	20,797	232,255

Appendix K Sheet 9 of 20

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Sales (MWh) by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2020)

	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	Total
Service Classification No. 1													
Heating	16,406	18,235	18,652	17,909	20,531	30,928	40,951	40,670	39,884	25,891	17,670	17,330	305,058
EEPS Lost MWh	(1,043)	(1,231)	(1,229)	(1,094)	(969)	(1,136)	(1,299)	(1,279)	(1,190)	(1,050)	(941)	(1,041)	(13,502)
Nonheating	139,752	166,826	166,216	144,002	122,945	137,467	161,027	157,820	144,832	129,105	121,991	137,218	1,729,202
EEPS Lost MWh	(5,477)	(6,461)	(6,452)	(5,744)	(5,087)	(5,966)	(6,821)	(6,716)	(6,246)	(5,513)	(4,938)	(5,463)	(70,884)
PV Lost MWh	(3,573)	(3,187)	(2,761)	(2,581)	(2,082)	(1,850)	(1,278)	(1,983)	(3,760)	(4,238)	(4,376)	(4,892)	(36,560)
	146,065	174,181	174,426	152,492	135,337	159,443	192,580	188,512	173,520	144,196	129,407	143,153	1,913,313
Service Classification No. 2													
Nondemand	12,403	14,278	13,649	12,878	11,843	14,120	15,556	16,261	14,539	14,161	12,384	12,333	164,405
EEPS Lost MWh	(529)	(589)	(550)	(513)	(481)	(560)	(634)	(640)	(579)	(539)	(481)	(525)	(6,620)
Primary	19,056	19,896	18,845	18,066	17,457	18,014	18,591	18,116	17,979	17,854	17,606	19,319	220,799
EEPS Lost MWh	(722)	(752)	(710)	(702)	(684)	(698)	(736)	(712)	(703)	(705)	(690)	(749)	(8,562)
Secondary	131,219	134,805	133,673	113,501	107,457	114,561	121,774	119,581	113,923	110,737	107,792	122,120	1,431,143
EEPS Lost MWh	(4,902)	(5,052)	(5,025)	(4,371)	(4,140)	(4,422)	(4,704)	(4,656)	(4,434)	(4,300)	(4,187)	(4,715)	(54,907)
PV Lost MWh	(963)	(848)	(725)	(668)	(532)	(466)	(317)	(485)	(907)	(1,008)	(1,025)	(1,130)	(9,073)
	155,562	161,739	159,158	138,191	130,920	140,549	149,530	147,465	139,818	136,200	131,398	146,654	1,737,184
Service Classification No. 3	25,189	25,584	24,532	22,916	22,394	23,590	24,146	21,157	22,021	21,247	22,249	23,905	278,930
EEPS Lost MWh	(949)	(963)	(922)	(885)	(875)	(910)	(947)	(826)	(854)	(835)	(869)	(921)	(10,755)
	24,240	24,622	23,610	22,031	21,519	22,680	23,199	20,331	21,167	20,412	21,380	22,984	268,176
Service Classification No. 5	800	894	987	1,141	1,230	1,355	1,291	1,076	1,045	923	829	738	12,310
Service Classification No. 6													
Heating	670	540	530	460	520	910	640	1,080	760	890	420	590	8,010
Nonheating	1,500	1,110	1,080	780	730	870	880	910	960	750	720	730	11,020
	2,170	1,650	1,610	1,240	1,250	1,780	1,520	1,990	1,720	1,640	1,140	1,320	19,030
Service Classification No. 8	1,080	1,200	1,330	1,530	1,660	1,820	1,670	1,390	1,350	1,190	1,070	950	16,240
Service Classification No. 9	193	193	193	191	191	190	196	190	190	184	188	187	2,286
Service Classification No. 13													
Transmission	64,732	65,304	60,558	62,014	56,054	54,160	54,494	52,590	59,470	59,400	61,172	61,226	711,174
Substation	14,410	14,924	14,042	13,422	14,714	13,868	12,862	12,166	12,720	12,246	13,448	13,470	162,292
	79,142	80,228	74,600	75,436	70,768	68,028	67,356	64,756	72,190	71,646	74,620	74,696	873,466
Interdepartmental	90	100	90	90	80	80	90	90	80	80	80	90	1,040
Total	409,342	444,807	436,004	392,341	362,956	395,925	437,433	425,800	411,080	376,471	360,113	390,773	4,843,045

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Base Delivery Revenues (Excluding Revenue Tax) by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 20120)

	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	Total
Service Classification No. 1													
Heating	$ 1,894,860	$ 2,038,770	$ 2,077,110	$ 2,021,560	$ 2,266,780	$ 3,170,560	$ 4,043,720	$ 4,004,840	$ 3,974,020	$ 2,732,230	$ 2,016,550	$ 1,976,260	$ 32,217,260
Nonheating	$ 16,195,310	$ 18,547,180	$ 18,527,960	$ 16,647,760	$ 14,878,470	$ 16,130,230	$ 18,188,490	$ 17,738,990	$ 16,713,460	$ 15,223,280	$ 14,631,190	$ 15,894,430	$ 199,316,750
Unbilled	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 18,090,170	$ 20,585,950	$ 20,605,070	$ 18,669,320	$ 17,145,250	$ 19,300,790	$ 22,232,210	$ 21,743,830	$ 20,687,480	$ 17,955,510	$ 16,647,740	$ 17,870,690	$ 231,534,010
Service Classification No. 2													
Nondemand	$ 1,560,700	$ 1,693,260	$ 1,627,170	$ 1,617,670	$ 1,528,240	$ 1,685,590	$ 1,731,210	$ 1,789,130	$ 1,695,950	$ 1,691,780	$ 1,567,770	$ 1,599,590	$ 19,788,060
Primary	$ 563,640	$ 526,120	$ 526,510	$ 496,330	$ 485,400	$ 501,746	$ 461,970	$ 467,390	$ 465,640	$ 498,540	$ 497,660	$ 541,590	$ 6,056,614
Secondary	$ 6,382,910	$ 6,158,410	$ 6,263,540	$ 5,664,300	$ 5,417,780	$ 5,400,230	$ 5,383,000	$ 5,279,300	$ 5,218,200	$ 5,354,640	$ 5,426,500	$ 6,004,020	$ 67,939,200
Unbilled	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 8,507,250	$ 8,377,790	$ 8,417,220	$ 7,778,300	$ 7,431,420	$ 7,587,566	$ 7,576,180	$ 7,535,820	$ 7,379,790	$ 7,544,960	$ 7,491,930	$ 8,145,200	$ 93,783,874
Service Classification No. 3	$ 664,230	$ 637,760	$ 699,720	$ 621,060	$ 639,360	$ 668,640	$ 616,250	$ 550,760	$ 557,890	$ 581,320	$ 631,680	$ 660,730	$ 7,528,433
Service Classification No. 5	$ 163,436	$ 164,556	$ 165,666	$ 167,516	$ 168,586	$ 170,076	$ 169,316	$ 166,736	$ 166,356	$ 164,906	$ 163,786	$ 162,696	$ 1,993,632
Service Classification No. 6	$ 156,580	$ 124,970	$ 122,040	$ 99,700	$ 99,850	$ 132,990	$ 116,500	$ 145,940	$ 128,840	$ 124,360	$ 93,060	$ 104,630	$ 1,449,460
Service Classification No. 8	$ 455,518	$ 455,572	$ 455,631	$ 455,721	$ 455,779	$ 455,851	$ 455,784	$ 455,658	$ 455,640	$ 455,568	$ 455,514	$ 455,460	$ 5,467,696
Service Classification No. 9	$ 19,890	$ 19,860	$ 19,820	$ 19,780	$ 19,740	$ 19,690	$ 19,690	$ 19,650	$ 19,610	$ 19,550	$ 19,520	$ 19,480	$ 236,280
Service Classification No. 13													
Transmission	$ 665,930	$ 699,190	$ 666,590	$ 693,050	$ 609,690	$ 589,400	$ 558,690	$ 568,320	$ 636,300	$ 623,800	$ 644,820	$ 644,490	$ 6,845,444
Substation	$ 233,140	$ 235,380	$ 224,770	$ 221,960	$ 213,550	$ 219,460	$ 234,390	$ 212,240	$ 214,120	$ 196,790	$ 230,410	$ 218,730	$ 2,610,092
	$ 899,070	$ 934,570	$ 891,360	$ 915,010	$ 823,240	$ 808,860	$ 793,080	$ 780,560	$ 850,420	$ 820,590	$ 875,230	$ 863,220	$ 9,455,536
Interdepartmental	$ 960	$ 1,070	$ 960	$ 960	$ 860	$ 860	$ 960	$ 960	$ 860	$ 860	$ 860	$ 960	$ 11,130
Total Base Revenue	$ 28,957,104	$ 31,302,098	$ 31,377,487	$ 28,727,367	$ 26,784,085	$ 29,145,323	$ 31,979,970	$ 31,399,914	$ 30,246,886	$ 27,667,624	$ 26,379,320	$ 28,283,066	$ 351,460,051
Total Base Revenue Excluding Unbilled	$ 28,957,104	$ 31,302,098	$ 31,377,487	$ 28,727,367	$ 26,784,085	$ 29,145,323	$ 31,979,970	$ 31,399,914	$ 30,246,886	$ 27,667,624	$ 26,379,320	$ 28,283,066	$ 351,460,051

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Customers by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2020)

	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	Average
Service Classification No. 1													
Heating	26,832	26,771	26,837	26,748	26,865	26,834	26,904	26,116	27,653	26,801	26,873	26,804	26,837
Nonheating	231,997	232,557	232,368	232,628	232,138	233,389	233,405	227,758	239,673	233,557	233,469	233,921	233,072
	258,829	259,328	259,205	259,376	259,003	260,223	260,309	253,874	267,326	260,358	260,342	260,725	259,908
Service Classification No. 2													
Nondemand	29,186	30,228	29,148	30,150	29,052	30,211	29,255	29,878	29,832	30,300	29,362	30,559	29,763
Primary	155	155	155	155	155	151	156	152	153	161	160	163	156
Secondary	11,701	11,674	11,722	11,686	11,630	11,684	11,606	11,408	11,986	11,757	11,803	11,772	11,702
	41,042	42,057	41,025	41,991	40,837	42,046	41,017	41,438	41,971	42,218	41,325	42,494	41,622
Service Classification No. 3	31	32	32	31	31	31	31	30	31	32	32	32	31
Service Classification No. 5	3,979	3,960	3,997	3,998	3,971	4,002	3,889	3,972	3,950	3,959	3,880	3,988	3,962
Service Classification No. 6													
Heating	320	370	320	370	320	370	320	370	320	370	320	370	345
Nonheating	670	640	670	640	670	640	670	640	670	640	670	640	655
	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	1,000
Service Classification No. 8	210	210	210	210	210	210	210	210	210	210	210	210	210
Service Classification No. 9	193	193	193	191	191	190	196	190	190	184	188	187	191
Service Classification No. 13													
Transmission	8	8	8	8	8	8	8	8	8	8	8	8	8
Substation	5	5	5	5	5	5	5	5	5	5	5	5	5
	13	13	13	13	13	13	13	13	13	13	13	13	13
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	305,288	306,804	305,666	306,821	305,247	307,726	306,656	300,738	314,682	307,985	306,981	308,660	306,938

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Demand Determinants by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2020)

	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	Total
Service Classification No. 2													
Primary kW	54,446	49,740	50,253	46,925	45,939	48,037	43,235	44,185	43,851	46,984	46,949	51,517	572,063
EEPS Lost kW	(2,062)	(1,879)	(1,893)	(1,824)	(1,800)	(1,863)	(1,712)	(1,737)	(1,714)	(1,855)	(1,841)	(1,996)	(22,175)
Secondary kW	437,397	414,785	424,359	378,337	358,190	352,495	347,926	341,660	335,068	351,546	359,307	407,067	4,508,135
EEPS Lost kW	(16,341)	(15,544)	(15,952)	(14,569)	(13,801)	(13,606)	(13,440)	(13,302)	(13,041)	(13,651)	(13,958)	(15,716)	(172,920)
PV Lost kW	(3,211)	(2,608)	(2,300)	(2,226)	(1,772)	(1,433)	(906)	(1,387)	(2,668)	(3,200)	(3,418)	(3,766)	(28,895)
	470,228	444,493	454,468	406,643	386,756	383,632	375,103	369,420	361,496	379,825	387,039	437,106	4,856,209
Service Classification No. 3 kW	54,759	52,212	57,722	50,924	52,692	55,506	50,834	45,015	45,404	47,216	51,742	54,330	618,355
EEPS Lost kW	(2,063)	(1,964)	(2,168)	(1,968)	(2,058)	(2,140)	(1,994)	(1,758)	(1,761)	(1,856)	(2,021)	(2,092)	(23,843)
	52,696	50,248	55,554	48,957	50,634	53,366	48,840	43,257	43,643	45,360	49,721	52,237	594,512
Service Classification No. 13													
Transmission kW	103,640	109,304	103,644	107,548	93,846	90,342	85,255	87,258	98,258	96,318	100,062	99,937	1,175,412
Substation kW	20,197	20,408	19,355	19,128	18,335	18,909	20,104	18,226	18,393	16,726	19,967	18,824	228,572
	123,837	129,712	122,999	126,676	112,181	109,251	105,359	105,484	116,651	113,044	120,029	118,761	1,403,984
Total kW	646,761	624,453	633,021	582,276	549,571	546,248	529,302	518,162	521,790	538,228	556,789	608,104	6,854,705
Service Classification No. 3 RkVa	10,952	10,442	12,410	10,185	9,221	6,938	5,846	5,627	6,811	9,443	10,348	10,866	109,089
EEPS Lost RkVa	(413)	(393)	(466)	(394)	(360)	(268)	(229)	(220)	(264)	(371)	(404)	(418)	(4,200)
	10,539	10,050	11,944	9,791	8,861	6,671	5,617	5,407	6,546	9,072	9,944	10,447	104,890
Service Classification No. 13													
Transmission RkVa	5,810	6,300	6,570	11,170	6,480	6,530	5,070	2,680	7,710	6,220	5,370	5,860	75,770
Substation RkVa	4,850	4,970	5,110	4,510	4,100	4,180	7,510	3,860	4,070	3,640	4,400	4,340	55,540
	10,660	11,270	11,680	15,680	10,580	10,710	12,580	6,540	11,780	9,860	9,770	10,200	131,310
Total RkVa	21,199	21,320	23,624	25,471	19,441	17,381	18,197	11,947	18,326	18,932	19,714	20,647	236,200

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Sales (MWh) by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2021)

	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	Total
Service Classification No. 1													
Heating	16,367	18,193	18,609	17,845	20,457	30,816	40,857	40,575	39,792	25,797	17,607	17,267	304,182
EEPS Lost MWh	(1,464)	(1,728)	(1,725)	(1,494)	(1,323)	(1,551)	(1,774)	(1,746)	(1,624)	(1,434)	(1,284)	(1,421)	(18,568)
Nonheating	140,854	168,136	167,522	145,246	124,008	138,655	162,747	159,505	146,380	130,486	123,298	138,687	1,745,524
EEPS Lost MWh	(7,688)	(9,070)	(9,058)	(7,842)	(6,945)	(8,144)	(9,312)	(9,169)	(8,526)	(7,526)	(6,741)	(7,458)	(97,480)
PV Lost MWh	(5,433)	(4,800)	(4,120)	(3,818)	(3,055)	(2,693)	(1,846)	(2,844)	(5,356)	(5,998)	(6,156)	(6,840)	(52,961)
	142,636	170,730	171,228	149,937	133,142	157,082	190,672	186,320	170,664	141,325	126,724	140,235	1,880,697
Service Classification No. 2													
Nondemand	12,452	14,336	13,704	12,925	11,884	14,170	15,604	16,312	14,584	14,199	12,419	12,367	164,956
EEPS Lost MWh	(730)	(813)	(759)	(696)	(652)	(759)	(859)	(867)	(784)	(731)	(651)	(712)	(9,013)
Primary	19,043	19,876	18,835	18,042	17,439	17,989	18,564	18,087	17,953	17,815	17,574	19,278	220,495
EEPS Lost MWh	(996)	(1,037)	(980)	(951)	(927)	(947)	(998)	(965)	(952)	(955)	(936)	(1,015)	(11,658)
Secondary	131,592	135,190	134,058	113,771	107,705	114,823	122,022	119,816	114,144	110,905	107,954	122,308	1,434,288
EEPS Lost MWh	(6,766)	(6,973)	(6,935)	(5,923)	(5,611)	(5,993)	(6,375)	(6,309)	(6,009)	(5,828)	(5,675)	(6,389)	(74,786)
PV Lost MWh	(1,236)	(1,076)	(910)	(830)	(654)	(568)	(383)	(581)	(1,077)	(1,187)	(1,198)	(1,309)	(11,009)
	153,359	159,503	157,013	136,338	129,184	138,716	147,575	145,493	137,858	134,218	129,487	144,529	1,713,272
Service Classification No. 3	25,185	25,580	24,525	22,899	22,379	23,584	24,138	21,143	22,000	21,220	22,218	23,873	278,744
EEPS Lost MWh	(1,310)	(1,329)	(1,272)	(1,200)	(1,185)	(1,233)	(1,284)	(1,120)	(1,158)	(1,132)	(1,178)	(1,248)	(14,646)
	23,875	24,251	23,253	21,699	21,194	22,351	22,854	20,023	20,842	20,088	21,040	22,625	264,098
Service Classification No. 5	799	893	985	1,139	1,229	1,353	1,291	1,076	1,044	923	829	738	12,299
Service Classification No. 6													
Heating	670	540	530	460	520	910	640	1,080	760	890	420	590	8,010
Nonheating	1,500	1,110	1,080	780	730	870	880	910	960	750	720	730	11,020
	2,170	1,650	1,610	1,240	1,250	1,780	1,520	1,990	1,720	1,640	1,140	1,320	19,030
Service Classification No. 8	1,030	1,150	1,270	1,470	1,590	1,750	1,600	1,330	1,290	1,140	1,030	910	15,560
Service Classification No. 9	186	186	186	184	184	184	189	184	184	178	182	181	2,208
Service Classification No. 13													
Transmission	64,732	65,304	60,558	62,014	56,054	54,160	54,494	52,590	59,470	59,400	61,172	61,226	711,174
Substation	14,416	14,930	14,040	13,430	14,712	13,878	12,862	12,166	12,720	12,246	13,448	13,470	162,318
	79,148	80,234	74,598	75,444	70,766	68,038	67,356	64,756	72,190	71,646	74,620	74,696	873,492
Interdepartmental	90	100	90	90	80	80	90	90	80	80	80	90	1,040
Total	403,293	438,697	430,233	387,541	358,619	391,334	433,148	421,262	405,873	371,238	355,132	385,324	4,781,696

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Base Delivery Revenues (Excluding Revenue Tax) by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2021)

	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	Total
Service Classification No. 1													
Heating	$ 1,982,670	$ 2,134,330	$ 2,176,530	$ 2,122,710	$ 2,397,300	$ 3,387,860	$ 4,349,860	$ 4,309,550	$ 4,274,910	$ 2,907,670	$ 2,122,400	$ 2,074,420	$ 34,240,210
Nonheating	$ 17,043,840	$ 19,650,710	$ 19,654,800	$ 17,628,890	$ 15,703,750	$ 17,079,390	$ 19,405,510	$ 18,893,960	$ 17,660,370	$ 16,020,530	$ 15,376,940	$ 16,754,300	$ 210,872,990
Unbilled	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 19,026,510	$ 21,785,040	$ 21,831,330	$ 19,751,600	$ 18,101,050	$ 20,467,250	$ 23,755,370	$ 23,203,510	$ 21,935,280	$ 18,928,200	$ 17,499,340	$ 18,828,720	$ 245,113,200
Service Classification No. 2													
Nondemand	$ 1,665,640	$ 1,816,610	$ 1,745,400	$ 1,728,630	$ 1,629,180	$ 1,808,670	$ 1,867,750	$ 1,933,010	$ 1,822,810	$ 1,815,140	$ 1,674,070	$ 1,703,130	$ 21,210,040
Primary	$ 582,810	$ 543,570	$ 544,170	$ 513,350	$ 502,310	$ 518,970	$ 477,700	$ 483,340	$ 481,620	$ 514,920	$ 514,650	$ 559,690	$ 6,264,735
Secondary	$ 6,737,960	$ 6,494,790	$ 6,610,960	$ 5,981,930	$ 5,722,480	$ 5,697,990	$ 5,673,720	$ 5,562,040	$ 5,496,450	$ 5,644,680	$ 5,724,310	$ 6,336,110	$ 71,761,369
Unbilled	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	$ 8,986,410	$ 8,854,970	$ 8,900,530	$ 8,223,910	$ 7,853,970	$ 8,025,630	$ 8,019,170	$ 7,978,390	$ 7,800,880	$ 7,974,740	$ 7,913,030	$ 8,598,930	$ 99,236,144
Service Classification No. 3	$ 687,760	$ 660,570	$ 722,390	$ 643,230	$ 662,110	$ 692,800	$ 636,610	$ 570,750	$ 578,050	$ 601,920	$ 653,780	$ 683,880	$ 7,793,850
Service Classification No. 5	$ 178,813	$ 179,943	$ 181,043	$ 182,883	$ 183,963	$ 185,453	$ 184,703	$ 182,133	$ 181,753	$ 180,303	$ 179,173	$ 178,083	$ 2,178,242
Service Classification No. 6	$ 165,420	$ 131,570	$ 128,480	$ 104,530	$ 104,730	$ 140,150	$ 122,550	$ 154,000	$ 135,730	$ 130,910	$ 97,480	$ 109,800	$ 1,525,350
Service Classification No. 8	$ 487,576	$ 487,630	$ 487,684	$ 487,774	$ 487,828	$ 487,900	$ 487,832	$ 487,711	$ 487,693	$ 487,625	$ 487,576	$ 487,522	$ 5,852,351
Service Classification No. 9	$ 20,420	$ 20,380	$ 20,340	$ 20,300	$ 20,260	$ 20,220	$ 20,190	$ 20,140	$ 20,100	$ 20,040	$ 20,000	$ 19,960	$ 242,350
Service Classification No. 13													
Transmission	$ 773,430	$ 812,130	$ 774,080	$ 804,290	$ 707,780	$ 684,130	$ 648,530	$ 660,080	$ 738,620	$ 724,270	$ 748,880	$ 748,430	$ 8,821,486
Substation	$ 251,440	$ 253,860	$ 242,350	$ 239,470	$ 230,340	$ 236,830	$ 252,570	$ 228,960	$ 230,970	$ 212,340	$ 248,490	$ 235,910	$ 2,822,134
	$ 1,024,870	$ 1,065,990	$ 1,016,430	$ 1,043,760	$ 938,120	$ 920,960	$ 901,100	$ 889,040	$ 969,590	$ 936,610	$ 997,370	$ 984,340	$ 11,643,620
Interdepartmental	$ 960	$ 1,070	$ 960	$ 960	$ 860	$ 860	$ 960	$ 960	$ 860	$ 860	$ 860	$ 960	$ 11,130
Total Base Revenue	$ 30,578,739	$ 33,187,163	$ 33,289,187	$ 30,458,947	$ 28,352,891	$ 30,941,223	$ 34,128,485	$ 33,486,634	$ 32,109,936	$ 29,261,208	$ 27,848,609	$ 29,892,195	$ 373,596,237
Total Base Revenue Excluding Unbilled	$ 30,578,739	$ 33,187,163	$ 33,289,187	$ 30,458,947	$ 28,352,891	$ 30,941,223	$ 34,128,485	$ 33,486,634	$ 32,109,936	$ 29,261,208	$ 27,848,609	$ 29,892,195	$ 373,596,237

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Customers by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2021)

	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	Average
Service Classification No. 1													
Heating	26,901	26,839	26,905	26,817	26,933	26,902	26,972	26,183	27,723	26,869	26,942	26,872	26,905
Nonheating	233,152	233,713	233,525	233,785	233,293	234,549	234,567	228,891	240,865	234,718	234,631	235,084	234,231
	260,053	260,552	260,430	260,602	260,226	261,451	261,539	255,074	268,588	261,587	261,573	261,956	261,136
Service Classification No. 2													
Nondemand	29,188	30,231	29,151	30,153	29,055	30,214	29,258	29,880	29,835	30,302	29,365	30,562	29,766
Primary	155	155	154	155	155	151	156	152	153	160	160	163	156
Secondary	11,684	11,658	11,707	11,668	11,614	11,669	11,591	11,391	11,971	11,743	11,786	11,756	11,687
	41,027	42,044	41,012	41,976	40,824	42,034	41,005	41,423	41,959	42,205	41,311	42,481	41,608
Service Classification No. 3	31	32	31	31	31	31	30	30	31	32	32	32	31
Service Classification No. 5	3,934	3,915	3,952	3,953	3,926	3,957	3,845	3,927	3,905	3,914	3,836	3,943	3,917
Service Classification No. 6													
Heating	320	370	320	370	320	370	320	370	320	370	320	370	345
Nonheating	670	640	670	640	670	640	670	640	670	640	670	640	655
	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	1,000
Service Classification No. 8	210	210	210	210	210	210	210	210	210	210	210	210	210
Service Classification No. 9	186	186	186	184	184	184	189	184	184	178	182	181	184
Service Classification No. 13													
Transmission	8	8	8	8	8	8	8	8	8	8	8	8	8
Substation	5	5	5	5	5	5	5	5	5	5	5	5	5
	13	13	13	13	13	13	13	13	13	13	13	13	13
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Customers	306,445	307,963	306,825	307,980	306,405	308,891	307,822	301,872	315,881	309,150	308,148	309,827	308,101

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Electric Demand Determinants by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2021)

	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	Total
Service Classification No. 2													
Primary kW	54,409	49,690	50,227	46,862	45,892	47,971	43,172	44,115	43,788	46,882	46,864	51,408	571,278
EEPS Lost kW	(2,846)	(2,593)	(2,612)	(2,471)	(2,440)	(2,524)	(2,320)	(2,353)	(2,323)	(2,514)	(2,495)	(2,705)	(30,197)
Secondary kW	438,640	415,969	425,581	379,237	359,017	353,302	348,634	342,331	335,718	352,079	359,847	407,693	4,518,048
EEPS Lost kW	(22,555)	(21,454)	(22,017)	(19,744)	(18,703)	(18,439)	(18,214)	(18,027)	(17,674)	(18,500)	(18,916)	(21,298)	(235,541)
PV Lost kW	(4,120)	(3,309)	(2,888)	(2,766)	(2,180)	(1,746)	(1,094)	(1,661)	(3,167)	(3,768)	(3,993)	(4,365)	(35,057)
	463,528	438,302	448,291	401,117	381,585	378,563	370,179	364,405	356,341	374,179	381,307	430,733	4,788,530
Service Classification No. 3 kW	54,750	52,204	57,706	50,887	52,656	55,492	50,817	44,985	45,361	47,156	51,670	54,257	617,940
EEPS Lost kW	(2,847)	(2,711)	(2,993)	(2,667)	(2,789)	(2,900)	(2,703)	(2,382)	(2,387)	(2,515)	(2,739)	(2,835)	(32,468)
	51,903	49,493	54,713	48,220	49,867	52,592	48,114	42,603	42,974	44,640	48,931	51,421	585,472
Service Classification No. 13													
Transmission kW	103,640	109,304	103,644	107,548	93,846	90,342	85,255	87,258	98,258	96,318	100,062	99,937	1,175,412
Substation kW	20,202	20,413	19,353	19,136	18,334	18,919	20,104	18,226	18,393	16,726	19,967	18,824	228,597
	123,842	129,717	122,997	126,684	112,180	109,261	105,359	105,484	116,651	113,044	120,029	118,761	1,404,009
Total kW	639,273	617,512	626,001	576,022	543,632	540,415	523,652	512,492	515,966	531,863	550,267	600,915	6,778,011
Service Classification No. 3 RkVa	10,950	10,441	12,407	10,177	9,215	6,936	5,844	5,623	6,804	9,431	10,334	10,851	109,014
EEPS Lost RkVa	(569)	(542)	(643)	(533)	(488)	(363)	(311)	(298)	(358)	(503)	(548)	(567)	(5,724)
	10,381	9,899	11,763	9,644	8,727	6,574	5,533	5,325	6,446	8,928	9,786	10,284	103,290
Service Classification No. 13													
Transmission RkVa	5,810	6,300	6,570	11,170	6,480	6,530	5,070	2,680	7,710	6,220	5,370	5,860	75,770
Substation RkVa	4,850	4,970	5,110	4,510	4,100	4,190	7,510	3,860	4,070	3,640	4,400	4,340	55,550
	10,660	11,270	11,680	15,680	10,580	10,720	12,580	6,540	11,780	9,860	9,770	10,200	131,320
Total RkVa	21,041	21,169	23,443	25,324	19,307	17,294	18,113	11,865	18,226	18,788	19,556	20,484	234,610

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Gas Sales, Base Revenues and Customers By Service Classification
12 Months Ended June 30, 2019, June 30, 2020 & June 30, 2021

Sales & Transport (Mcf)	Twelve Months Ended June 30, 2019	Twelve Months Ended June 30, 2020	Twelve Months Ended June 30, 2021
Service Classification Nos. 1 & 12			
Heat	5,765,046	5,854,239	5,943,414
Nonheating	147,305	142,330	137,351
	5,912,351	5,996,569	6,080,765
Service Classification Nos. 2, 6 & 13			
Heat	5,920,397	6,006,029	6,076,766
Nonheating	882,361	875,952	864,225
	6,802,758	6,881,981	6,940,991
Service Classification No. 8	115,857	115,857	115,857
Service Classification No. 9	1,421,952	1,421,952	1,421,952
Service Classification No. 11	1,775,389	1,775,389	1,775,389
Service Classification No. 14	-	-	-
Sales for Resale	-	-	-
Interdepartmental	24,000	24,000	24,000
Total Sales & Transport	16,052,306	16,215,747	16,358,953
Base Revenue ($)			
Service Classification Nos. 1 & 12			
Heat	$ 63,773,020	$ 69,106,280	$ 75,460,470
Nonheating	$ 3,283,020	$ 3,256,910	$ 3,262,090
	$ 67,056,040	$ 72,363,190	$ 78,722,560
Service Classification Nos. 2, 6 & 13			
Heat	$ 27,934,440	$ 30,182,000	$ 32,801,740
Nonheating	$ 3,710,100	$ 3,925,140	$ 4,164,900
	$ 31,644,540	$ 34,107,140	$ 36,966,640
Service Classification No. 8	$ 300,060	$ 300,060	$ 300,060
Service Classification No. 9	$ 2,300,370	$ 2,300,370	$ 2,300,370
Service Classification No. 11	$ 2,553,309	$ 2,735,266	$ 2,952,742
Service Classification No. 14	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -
Interdepartmental	$ 74,508	$ 80,141	$ 86,998
Total Own Territory	$ 103,928,827	$ 111,886,167	$ 121,329,370
Customers			
Service Classification Nos. 1 & 12			
Heat	63,318	64,299	65,280
Nonheating	6,805	6,575	6,345
	70,124	70,874	71,625
Service Classification Nos. 2, 6 & 13			
Heat	10,653	10,817	10,981
Nonheating	1,158	1,144	1,129
	11,812	11,961	12,110
Service Classification No. 8	13	13	13
Service Classification No. 9	38	38	38
Service Classification No. 11	5	5	5
Interdepartmental	1	1	1
Total Sales & Transport Customers	81,992	82,892	83,792

Appendix K Sheet 18 of 20

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Gas Customers & Sales by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2019)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	145,328	100,664	96,854	211,643	442,168	776,477	1,032,470	1,049,315	880,443	610,059	299,154	120,471	5,765,046
Nonheating	6,632	4,918	4,924	5,725	8,701	14,226	18,457	22,782	22,117	18,568	12,040	8,215	147,305
	151,960	105,582	101,778	217,368	450,869	790,703	1,050,927	1,072,097	902,560	628,627	311,194	128,686	5,912,351
Service Classification Nos. 2, 6 & 13													
Heat	189,935	146,564	177,884	257,475	480,410	759,175	1,009,632	1,036,457	847,695	539,405	307,692	168,073	5,920,397
Nonheating	54,737	42,977	54,802	56,652	78,871	87,194	118,884	93,864	102,112	78,191	65,453	48,624	882,361
	244,672	189,541	232,686	314,127	559,281	846,369	1,128,516	1,130,321	949,807	617,596	373,145	216,697	6,802,758
Service Classification No. 8	5,800	9,050	9,560	12,640	15,910	11,237	10,660	7,580	5,350	7,640	11,810	8,620	115,857
Service Classification No. 9	72,610	70,820	70,520	108,900	145,530	170,232	183,890	162,880	144,980	122,760	95,990	72,840	1,421,952
Service Classification No. 11	80,764	80,938	78,899	121,240	169,493	228,658	264,302	235,389	191,700	149,122	101,068	73,816	1,775,389
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	240	160	150	380	1,350	2,900	4,010	5,380	4,800	2,780	1,380	470	24,000
Total Sales & Transport	556,046	456,091	493,593	774,655	1,342,433	2,050,098	2,642,305	2,613,647	2,199,197	1,528,525	894,587	501,129	16,052,306
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat	$ 3,010,610	$ 2,557,690	$ 2,535,910	$ 3,643,240	$ 5,738,340	$ 7,300,090	$ 8,608,310	$ 8,828,760	$ 7,919,430	$ 6,405,320	$ 4,434,960	$ 2,790,360	$ 63,773,020
Nonheating	$ 232,900	$ 215,870	$ 215,000	$ 222,960	$ 250,730	$ 293,600	$ 317,620	$ 351,640	$ 343,140	$ 318,870	$ 277,140	$ 243,550	$ 3,283,020
	$ 3,243,510	$ 2,773,560	$ 2,750,910	$ 3,866,200	$ 5,989,070	$ 7,593,690	$ 8,925,930	$ 9,180,400	$ 8,262,570	$ 6,724,190	$ 4,712,100	$ 3,033,910	$ 67,056,040
Service Classification Nos. 2, 6 & 13													
Heat	$ 1,177,640	$ 1,010,260	$ 1,124,680	$ 1,436,680	$ 2,301,230	$ 3,328,890	$ 4,196,530	$ 4,327,760	$ 3,679,620	$ 2,560,930	$ 1,675,690	$ 1,114,530	$ 27,934,440
Nonheating	$ 239,360	$ 196,670	$ 237,860	$ 244,870	$ 329,460	$ 359,480	$ 469,600	$ 390,090	$ 412,340	$ 329,720	$ 282,790	$ 217,860	$ 3,710,100
	$ 1,417,000	$ 1,206,930	$ 1,362,540	$ 1,681,550	$ 2,630,690	$ 3,688,370	$ 4,666,130	$ 4,717,850	$ 4,091,960	$ 2,890,650	$ 1,958,480	$ 1,332,390	$ 31,644,540
Service Classification No. 8	$ 15,020	$ 23,440	$ 24,760	$ 32,740	$ 41,200	$ 29,100	$ 27,610	$ 19,610	$ 13,870	$ 19,790	$ 30,600	$ 22,320	$ 300,060
Service Classification No. 9	$ 128,070	$ 124,090	$ 123,250	$ 183,180	$ 235,290	$ 264,350	$ 283,240	$ 251,730	$ 224,130	$ 189,390	$ 162,280	$ 131,370	$ 2,300,370
Service Classification No. 11	$ 201,235	$ 201,335	$ 200,725	$ 208,295	$ 216,725	$ 226,735	$ 232,785	$ 227,885	$ 220,565	$ 212,715	$ 204,475	$ 199,835	$ 2,553,309
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 745	$ 497	$ 466	$ 1,180	$ 4,191	$ 9,003	$ 12,449	$ 16,702	$ 14,902	$ 8,631	$ 4,284	$ 1,459	$ 74,508
Total Own Territory	$ 5,005,580	$ 4,329,852	$ 4,462,651	$ 5,973,145	$ 9,117,166	$ 11,811,248	$ 14,148,144	$ 14,414,177	$ 12,827,997	$ 10,045,365	$ 7,072,219	$ 4,721,284	$ 103,928,827
Customers													
Service Classification Nos. 1 & 12													
Heat	62,881	62,943	63,037	63,108	63,204	63,273	63,362	63,431	63,528	63,597	63,694	63,759	63,318
Nonheating	6,907	6,897	6,868	6,859	6,830	6,822	6,786	6,784	6,749	6,746	6,710	6,707	6,805
	69,788	69,840	69,905	69,967	70,034	70,095	70,148	70,215	70,277	70,343	70,404	70,466	70,124
Service Classification Nos. 2, 6 & 13													
Heat	10,566	10,600	10,599	10,629	10,620	10,656	10,653	10,688	10,680	10,708	10,702	10,739	10,653
Nonheating	1,168	1,157	1,168	1,151	1,169	1,148	1,171	1,144	1,166	1,147	1,167	1,142	1,158
	11,734	11,757	11,767	11,780	11,789	11,804	11,824	11,832	11,846	11,855	11,869	11,881	11,812
Service Classification No. 8	13	13	13	13	13	13	13	13	13	13	13	13	13
Service Classification No. 9	38	38	38	38	38	38	38	38	38	38	38	38	38
Service Classification No. 11	5	5	5	5	5	5	5	5	5	5	5	5	5
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	81,579	81,654	81,729	81,804	81,880	81,956	82,029	82,104	82,180	82,255	82,330	82,404	81,992

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Gas Customers & Sales by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2020)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	147,595	102,232	98,360	214,933	449,031	788,516	1,048,453	1,065,537	894,034	619,466	303,760	122,322	5,854,239
Nonheating	6,412	4,754	4,759	5,533	8,409	13,749	17,832	22,015	21,364	17,939	11,629	7,935	142,330
	154,007	106,986	103,119	220,466	457,440	802,265	1,066,285	1,087,552	915,398	637,405	315,389	130,257	5,996,569
Service Classification Nos. 2, 6 & 13													
Heat	193,262	149,218	180,935	261,236	487,641	770,497	1,024,080	1,050,787	858,971	546,795	312,065	170,542	6,006,029
Nonheating	54,382	42,562	54,409	56,235	78,506	86,873	118,128	93,225	101,226	77,482	64,767	48,157	875,952
	247,644	191,780	235,344	317,471	566,147	857,370	1,142,208	1,144,012	960,197	624,277	376,832	218,699	6,881,981
Service Classification No. 8	5,800	9,050	9,560	12,640	15,910	11,237	10,660	7,580	5,350	7,640	11,810	8,620	115,857
Service Classification No. 9	72,610	70,820	70,520	108,900	145,530	170,232	183,890	162,880	144,980	122,760	95,990	72,840	1,421,952
Service Classification No. 11	80,764	80,938	78,899	121,240	169,493	228,658	264,302	235,389	191,700	149,122	101,068	73,816	1,775,389
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	240	160	150	380	1,350	2,900	4,010	5,380	4,800	2,780	1,380	470	24,000
Total Sales & Transport	561,065	459,734	497,592	781,097	1,355,870	2,072,661	2,671,355	2,642,793	2,222,425	1,543,984	902,469	504,702	16,215,747
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat	$ 3,177,030	$ 2,669,020	$ 2,644,210	$ 3,885,410	$ 6,233,920	$ 7,986,080	$ 9,453,380	$ 9,699,950	$ 8,679,430	$ 6,980,690	$ 4,770,550	$ 2,926,610	$ 69,106,280
Nonheating	$ 227,820	$ 209,650	$ 208,800	$ 217,300	$ 246,980	$ 292,750	$ 318,490	$ 354,760	$ 345,690	$ 319,800	$ 275,380	$ 239,490	$ 3,256,910
	$ 3,404,850	$ 2,878,670	$ 2,853,010	$ 4,102,710	$ 6,480,900	$ 8,278,830	$ 9,771,870	$ 10,054,710	$ 9,025,120	$ 7,300,490	$ 5,045,930	$ 3,166,100	$ 72,363,190
Service Classification Nos. 2, 6 & 13													
Heat	$ 1,259,220	$ 1,075,670	$ 1,200,580	$ 1,540,130	$ 2,487,560	$ 3,611,980	$ 4,558,590	$ 4,700,290	$ 3,990,480	$ 2,768,860	$ 1,801,350	$ 1,187,290	$ 30,182,000
Nonheating	$ 252,500	$ 206,300	$ 250,700	$ 258,200	$ 349,560	$ 382,190	$ 499,110	$ 414,050	$ 436,900	$ 348,640	$ 298,010	$ 228,980	$ 3,925,140
	$ 1,511,720	$ 1,281,970	$ 1,451,280	$ 1,798,330	$ 2,837,120	$ 3,994,170	$ 5,057,700	$ 5,114,340	$ 4,427,380	$ 3,117,500	$ 2,099,360	$ 1,416,270	$ 34,107,140
Service Classification No. 8	$ 15,020	$ 23,440	$ 24,760	$ 32,740	$ 41,200	$ 29,100	$ 27,610	$ 19,610	$ 13,870	$ 19,790	$ 30,600	$ 22,320	$ 300,060
Service Classification No. 9	$ 128,070	$ 124,090	$ 123,250	$ 183,180	$ 235,290	$ 264,350	$ 283,240	$ 251,730	$ 224,130	$ 189,390	$ 162,280	$ 131,370	$ 2,300,370
Service Classification No. 11	$ 215,631	$ 215,751	$ 215,101	$ 223,161	$ 232,161	$ 242,831	$ 249,271	$ 244,051	$ 236,251	$ 227,861	$ 219,071	$ 214,131	$ 2,735,266
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 801	$ 534	$ 501	$ 1,269	$ 4,508	$ 9,684	$ 13,390	$ 17,965	$ 16,028	$ 9,283	$ 4,608	$ 1,569	$ 80,141
Total Own Territory	$ 5,276,092	$ 4,524,455	$ 4,667,901	$ 6,341,389	$ 9,831,178	$ 12,818,964	$ 15,403,081	$ 15,702,405	$ 13,942,779	$ 10,864,314	$ 7,561,849	$ 4,951,760	$ 111,886,167
Customers													
Service Classification Nos. 1 & 12													
Heat	63,862	63,925	64,018	64,089	64,185	64,254	64,344	64,412	64,509	64,578	64,676	64,740	64,299
Nonheating	6,677	6,666	6,638	6,629	6,600	6,591	6,556	6,553	6,519	6,516	6,480	6,476	6,575
	70,539	70,591	70,656	70,718	70,785	70,845	70,900	70,965	71,028	71,094	71,156	71,216	70,874
Service Classification Nos. 2, 6 & 13													
Heat	10,730	10,763	10,763	10,793	10,784	10,820	10,816	10,852	10,844	10,872	10,865	10,903	10,817
Nonheating	1,154	1,143	1,153	1,136	1,154	1,133	1,156	1,130	1,151	1,133	1,152	1,128	1,144
	11,884	11,906	11,916	11,929	11,938	11,953	11,972	11,982	11,995	12,005	12,017	12,031	11,961
Service Classification No. 8	13	13	13	13	13	13	13	13	13	13	13	13	13
Service Classification No. 9	38	38	38	38	38	38	38	38	38	38	38	38	38
Service Classification No. 11	5	5	5	5	5	5	5	5	5	5	5	5	5
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	82,480	82,554	82,629	82,704	82,780	82,855	82,929	83,004	83,080	83,156	83,230	83,304	82,892

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Gas Customers & Sales by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2021)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	149,863	103,801	99,868	218,222	455,894	800,552	1,064,431	1,081,753	907,623	628,868	308,365	124,174	5,943,414
Nonheating	6,192	4,591	4,594	5,342	8,117	13,271	17,206	21,247	20,612	17,309	11,216	7,654	137,351
	156,055	108,392	104,462	223,564	464,011	813,823	1,081,637	1,103,000	928,235	646,177	319,581	131,828	6,080,765
Service Classification Nos. 2, 6 & 13													
Heat	196,299	151,479	183,575	264,357	493,238	779,336	1,035,779	1,062,725	868,497	553,132	315,795	172,554	6,076,766
Nonheating	53,899	42,103	53,833	55,480	77,453	85,732	116,581	91,866	99,759	76,380	63,750	47,389	864,225
	250,198	193,582	237,408	319,837	570,691	865,068	1,152,360	1,154,591	968,256	629,512	379,545	219,943	6,940,991
Service Classification No. 8	5,800	9,050	9,560	12,640	15,910	11,237	10,660	7,580	5,350	7,640	11,810	8,620	115,857
Service Classification No. 9	72,610	70,820	70,520	108,900	145,530	170,232	183,890	162,880	144,980	122,760	95,990	72,840	1,421,952
Service Classification No. 11	80,764	80,938	78,899	121,240	169,493	228,658	264,302	235,389	191,700	149,122	101,068	73,816	1,775,389
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	240	160	150	380	1,350	2,900	4,010	5,380	4,800	2,780	1,380	470	24,000
Total Sales & Transport	565,667	462,942	500,999	786,561	1,366,985	2,091,917	2,696,859	2,668,820	2,243,321	1,557,991	909,374	507,517	16,358,953
Base Revenue ($)													
Service Classification Nos. 1 & 12													
Heat	$ 3,387,600	$ 2,815,390	$ 2,787,200	$ 4,183,960	$ 6,826,490	$ 8,792,360	$ 10,439,240	$ 10,716,580	$ 9,569,980	$ 7,661,700	$ 5,177,520	$ 3,102,450	$ 75,460,470
Nonheating	$ 225,140	$ 205,590	$ 204,700	$ 213,920	$ 245,680	$ 294,720	$ 322,170	$ 360,980	$ 351,330	$ 323,670	$ 276,240	$ 237,950	$ 3,262,090
	$ 3,612,740	$ 3,020,980	$ 2,991,900	$ 4,397,880	$ 7,072,170	$ 9,087,080	$ 10,761,410	$ 11,077,560	$ 9,921,310	$ 7,985,370	$ 5,453,760	$ 3,340,400	$ 78,722,560
Service Classification Nos. 2, 6 & 13													
Heat	$ 1,354,240	$ 1,150,810	$ 1,288,240	$ 1,659,950	$ 2,702,510	$ 3,940,230	$ 4,982,050	$ 5,137,440	$ 4,355,670	$ 3,012,390	$ 1,947,530	$ 1,270,680	$ 32,801,740
Nonheating	$ 267,990	$ 217,870	$ 265,640	$ 273,170	$ 371,160	$ 406,360	$ 531,780	$ 440,100	$ 464,410	$ 369,970	$ 315,200	$ 241,250	$ 4,164,900
	$ 1,622,230	$ 1,368,680	$ 1,553,880	$ 1,933,120	$ 3,073,670	$ 4,346,590	$ 5,513,830	$ 5,577,540	$ 4,820,080	$ 3,382,360	$ 2,262,730	$ 1,511,930	$ 36,966,640
Service Classification No. 8	$ 15,020	$ 23,440	$ 24,760	$ 32,740	$ 41,200	$ 29,100	$ 27,610	$ 19,610	$ 13,870	$ 19,790	$ 30,600	$ 22,320	$ 300,060
Service Classification No. 9	$ 128,070	$ 124,090	$ 123,250	$ 183,180	$ 235,290	$ 264,350	$ 283,240	$ 251,730	$ 224,130	$ 189,390	$ 162,280	$ 131,370	$ 2,300,370
Service Classification No. 11	$ 232,993	$ 233,123	$ 232,423	$ 240,993	$ 250,563	$ 261,873	$ 268,723	$ 263,173	$ 254,883	$ 245,973	$ 236,643	$ 231,383	$ 2,952,742
Service Classification No. 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sales for Resale	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interdepartmental	$ 870	$ 580	$ 544	$ 1,377	$ 4,894	$ 10,512	$ 14,536	$ 19,502	$ 17,400	$ 10,077	$ 5,002	$ 1,704	$ 86,998
Total Own Territory	$ 5,611,923	$ 4,770,893	$ 4,926,756	$ 6,789,290	$ 10,677,786	$ 13,999,505	$ 16,869,349	$ 17,209,115	$ 15,251,672	$ 11,832,960	$ 8,151,015	$ 5,239,106	$ 121,329,370
Customers													
Service Classification Nos. 1 & 12													
Heat	64,843	64,906	65,000	65,070	65,166	65,234	65,325	65,393	65,490	65,559	65,657	65,721	65,280
Nonheating	6,447	6,436	6,407	6,399	6,369	6,361	6,326	6,323	6,289	6,285	6,250	6,246	6,345
	71,290	71,342	71,407	71,469	71,535	71,595	71,651	71,716	71,779	71,844	71,907	71,967	71,625
Service Classification Nos. 2, 6 & 13													
Heat	10,894	10,927	10,926	10,957	10,948	10,984	10,980	11,016	11,008	11,036	11,029	11,067	10,981
Nonheating	1,139	1,128	1,138	1,122	1,139	1,119	1,141	1,115	1,136	1,118	1,137	1,113	1,129
	12,033	12,055	12,064	12,079	12,087	12,103	12,121	12,131	12,144	12,154	12,166	12,180	12,110
Service Classification No. 8	13	13	13	13	13	13	13	13	13	13	13	13	13
Service Classification No. 9	38	38	38	38	38	38	38	38	38	38	38	38	38
Service Classification No. 11	5	5	5	5	5	5	5	5	5	5	5	5	5
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	83,380	83,454	83,528	83,605	83,679	83,755	83,829	83,904	83,980	84,055	84,130	84,204	83,792

Central Hudson Gas & Electric Corporation

Electric Revenue Allocation- Rate Year 1

	Revenue Increase	Increase Percent
SC 1 Residential	$ 4,962,884	2.45%
SC 2 Non Demand	$ 431,870	2.58%
SC 2 Secondary	$ 1,856,372	3.11%
SC 2 Primary	$ 123,420	2.31%
SC 3 Primary	$ 162,911	2.48%
SC 5 Area Lighting	$ 51,260	3.11%
SC 6 Residential TOU	$ 29,234	2.27%
SC 8 Street Lighting	$ 194,821	3.87%
SC 9 Traffic Signals	$ 4,670	2.17%
SC 13 Substation	$ 60,143	3.14%
SC 13 Transmission	$ 138,616	2.48%
Total	$ 8,016,200	2.62%

Central Hudson Gas & Electric Corporation

Electric Revenue Allocation- Rate Year 2

	Revenue Increase	Increase Percent
SC 1 Residential	$ 12,172,546	5.79%
SC 2 Non Demand	$ 1,143,163	6.51%
SC 2 Secondary	$ 3,616,744	5.64%
SC 2 Primary	$ 243,198	4.17%
SC 3 Primary	$ 319,684	4.41%
SC 5 Area Lighting	$ 129,251	7.51%
SC 6 Residential TOU	$ 57,985	4.28%
SC 8 Street Lighting	$ 354,914	6.94%
SC 9 Traffic Signals	$ 9,202	4.18%
SC 13 Substation	$ 133,941	5.55%
SC 13 Transmission	$ 270,067	4.41%
Total	$ 18,450,694	5.73%

Central Hudson Gas & Electric Corporation

Electric Revenue Allocation- Rate Year 3

	Revenue Increase	Increase Percent
SC 1 Residential	$ 16,389,819	7.46%
SC 2 Non Demand	$ 1,539,995	8.27%
SC 2 Secondary	$ 4,844,070	7.26%
SC 2 Primary	$ 320,928	5.38%
SC 3 Primary	$ 422,131	5.69%
SC 5 Area Lighting	$ 176,805	9.67%
SC 6 Residential TOU	$ 77,853	5.51%
SC 8 Street Lighting	$ 481,186	8.96%
SC 9 Traffic Signals	$ 12,133	5.43%
SC 13 Substation	$ 190,163	7.16%
SC 13 Transmission	$ 432,294	5.69%
Total	$ 24,887,378	7.37%

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460

Gas Revenue Allocation - Rate Year 1

Base Revenue Allocation (Excluding Incremental MFC)	Base Rev Increase	Interruptible Revenues	Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ 4,460,558	$ (1,736,053)	$ 65,513,915	66.12%	4.34%
SC 2, 6 & 13	$ 2,107,172	$ (813,702)	$ 30,723,380	31.23%	4.40%
SC 11 Transmission	$ 54,904	$ (24,684)	$ 923,000	0.81%	3.38%
SC 11 Distribution	$ 7,309	$ (2,549)	$ 96,970	0.11%	5.16%
SC 11 - DLM	$ 82,468	$ (23,011)	$ 891,726	1.22%	7.14%
SC 11 - EG (Excl Danskammer)	$ 33,852	$ -	$ 603,252	0.50%	5.95%
Total	$ 6,746,263	$ (2,600,000)	$ 98,752,243	100.00%	4.38%

Energy Efficiency Allocation	EE Allocation	Base Rev Increase Incl EE	Interruptible Revenues	Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ 1,024,435	$ 5,484,992	$ (1,736,053)	$ 66,538,350	69.18%	5.97%
SC 2, 6 & 13	$ 119,196	$ 2,226,368	$ (813,702)	$ 30,842,575	28.08%	4.80%
SC 11 Transmission	$ 17,565	$ 72,469	$ (24,684)	$ 940,565	0.91%	5.35%
SC 11 Distribution	$ 879	$ 8,188	$ (2,549)	$ 97,849	0.10%	6.12%
SC 11 - DLM	$ 12,664	$ 95,132	$ (23,011)	$ 904,390	1.20%	8.67%
SC 11 - EG (Excl Danskammer)	$ 7,262	$ 41,114	$ -	$ 610,514	0.52%	7.22%
Total	$ 1,182,000	$ 7,928,263	$ (2,600,000)	$ 99,934,243	100.00%	5.63%

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460

Gas Revenue Allocation - Rate Year 2

	Base Rev Increase	Interruptible Revenues	Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ 6,186,578	$ (1,733,332)	$ 72,385,416	66.19%	6.56%
SC 2, 6 & 13	$ 2,928,732	$ (817,104)	$ 34,135,298	31.33%	6.59%
SC 11 Transmission	$ 85,306	$ (23,987)	$ 1,001,403	0.91%	6.52%
SC 11 Distribution	$ 8,878	$ (2,496)	$ 104,224	0.09%	6.52%
SC 11 - DLM	$ 82,085	$ (23,081)	$ 963,588	0.88%	6.52%
SC 11 - EG (Excl Danskammer)	$ 55,426	$ -	$ 666,226	0.59%	9.07%
Total	$ 9,347,005	$ (2,600,000)	$ 109,256,155	100.00%	6.58%

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460

Gas Revenue Allocation - Rate Year 3

	Base Rev Increase	Interruptible Revenues	Delivery Revenues	Increase as % of System	Delivery Increase Percent
SC 1 & 12	$ 7,176,674	$ (1,735,770)	$ 78,743,483	66.33%	7.42%
SC 2, 6 & 13	$ 3,376,670	$ (815,231)	$ 36,989,099	31.21%	7.44%
SC 11 Transmission	$ 97,756	$ (23,714)	$ 1,075,499	0.90%	7.39%
SC 11 Distribution	$ 10,173	$ (2,468)	$ 111,921	0.09%	7.39%
SC 11 - DLM	$ 94,060	$ (22,817)	$ 1,034,837	0.87%	7.39%
SC 11 - EG (Excl Danskammer)	$ 65,011	$ -	$ 731,011	0.60%	9.76%
Total	$ 10,820,344	$ (2,600,000)	$ 118,685,850	100.00%	7.44%

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Billing Determinants
(Excludes S.C. Nos. 5 & 8, Unbilled & Interdepartmental)

		12 Months Ending Jun-19 Rate Year 1	12 Months Ending Jun-20 Rate Year 2	12 Months Ending Jun-21 Rate Year 3
S.C. No. 1				
	Customer Months	3,100,972	3,118,900	3,133,633
	kWh	1,941,012,280	1,913,313,580	1,880,696,532
S.C. No. 2 - Non-Demand				
	Customer Months	356,558	357,161	357,194
	kWh	157,002,515	157,785,047	155,942,758
S.C. No. 2 - Secondary				
	Customer Months	140,449	140,426	140,238
	kWh	1,385,548,399	1,367,162,372	1,348,493,719
	kW	4,364,394	4,306,321	4,247,449
S.C. No. 2 - Primary				
	Customer Months	1,872	1,871	1,869
	kWh	215,254,061	212,236,655	208,836,502
	kW	557,701	549,888	541,081
S.C. No. 3				
	Customer Months	376	376	374
	kWh	271,759,398	268,175,167	264,097,935
	kW	602,460	594,512	585,472
	Rkva	106,295	104,890	103,290
S.C. No. 6				
	Customer Months	12,000	12,000	12,000
	On-Peak kWh	5,709,000	5,709,000	5,709,000
	Off-Peak kWh	13,321,000	13,321,000	13,321,000
S.C. No. 9 - Traffic Signals				
	Signal Face Months	61,202	59,762	58,322
	kWh	2,370,000	2,286,000	2,208,000
S.C. No. 13 - Substation				
	Customer Months	60	60	60
	kWh	153,752,000	162,292,000	162,318,000
	kW	220,025	228,572	228,597
	Rkva	50,190	55,540	55,550
S.C. No. 13 - Transmission				
	Customer Months	96	96	96
	kWh	711,174,000	711,174,000	711,174,000
	kW	1,175,412	1,175,412	1,175,412
	Rkva	75,770	75,770	75,770

Appendix M Sheet 2 of 11

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Proposed Monthly Electric Base Delivery Rates
(Excludes S.C. Nos. 5 & 8, Unbilled & Interdepartmental)

		Current Rates	12 Months Ending Jun-19 Rate Year 1	12 Months Ending Jun-20 Rate Year 2	12 Months Ending Jun-21 Rate Year 3
S.C. No. 1					
	Customer Charge	$ 24.00	$ 21.00	$ 20.00	$ 19.50
	kWh Delivery	$ 0.06586	$ 0.07563	$ 0.08349	$ 0.09283
S.C. No. 2 - Non-Demand					
	Customer Charge	$ 35.00	$ 32.00	$ 31.00	$ 30.50
	kWh Delivery	$ 0.02702	$ 0.03887	$ 0.04838	$ 0.05921
S.C. No. 2 - Secondary					
	Customer Charge	$ 84.00	$ 88.00	$ 92.50	$ 97.00
	HPP Customer Charge	$ 114.00	$ 118.00	$ 122.50	$ 127.00
	kWh Delivery	$ 0.00591	$ 0.00532	$ 0.00478	$ 0.00430
	kW Delivery	$ 9.06	$ 10.28	$ 11.10	$ 12.18
S.C. No. 2 - Primary					
	Customer Charge	$ 310.00	$ 341.00	$ 376.00	$ 414.00
	HPP Customer Charge	$ 340.00	$ 371.00	$ 406.00	$ 444.00
	kWh Delivery	$ 0.00168	$ 0.00151	$ 0.00136	$ 0.00122
	kW Delivery	$ 7.64	$ 8.63	$ 8.97	$ 9.43
S.C. No. 3					
	Customer Charge	$ 1,500.00	$ 1,650.00	$ 1,800.00	$ 1,950.00
	kWh Delivery	$ -	$ -	$ -	$ -
	kW Delivery	$ 9.84	$ 10.99	$ 11.38	$ 11.92
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 6					
	Customer Charge	$ 27.00	$ 24.00	$ 23.00	$ 22.50
	kWh Delivery On Pk	$ 0.09507	$ 0.10520	$ 0.11200	$ 0.12006
	kWh Delivery Off Pk	$ 0.03169	$ 0.03507	$ 0.03733	$ 0.04002
S.C. No. 6 (5 Hour On-Peak)					
	Customer Charge	$ 27.00	$ 24.00	$ 23.00	$ 22.50
	kWh Delivery On Pk	$ 0.07494	$ 0.08522	$ 0.09305	$ 0.10237
	kWh Delivery Off Pk	$ 0.06116	$ 0.07144	$ 0.07928	$ 0.08860
S.C. No. 9					
	Signal Faces	$ 3.52	$ 3.68	$ 3.83	$ 4.03
S.C. No. 13 - Substation					
	Customer Charge	$ 3,800.00	$ 4,200.00	$ 4,700.00	$ 5,200.00
	kWh Delivery	$ -	$ -	$ -	$ -
	kW Delivery	$ 7.49	$ 9.25	$ 10.18	$ 10.96
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 13 - Transmission					
	Customer Charge	$ 5,020.00	$ 6,500.00	$ 7,500.00	$ 8,500.00
	kWh Delivery	$ -	$ -	$ -	$ -
	kW Delivery	$ 4.30	$ 4.62	$ 5.80	$ 6.76
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83
Energy Efficiency Exemption Credit Rate per kW:					
	S.C. No. 2 - Secondary		$ 0.74	$ 0.71	$ 0.66
	S.C. No. 2 - Primary		$ 0.80	$ 0.77	$ 0.71
	S.C. No. 3		$ 0.98	$ 0.93	$ 0.86
	S.C. No. 13 - Substation		$ 1.59	$ 1.51	$ 1.39
	S.C. No. 13 - Transmission		$ 0.32	$ 1.13	$ 1.16

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Proposed Electric Merchant Function Charges

	Current Rates	12 Months Ending Jun-19 Rate Year 1	12 Months Ending Jun-20 Rate Year 2	12 Months Ending Jun-21 Rate Year 3
MFC Administration Charge per kWh				
S.C. No. 1 - Residential	$ 0.00163	$ 0.00180	$ 0.00183	$ 0.00186
S.C. No. 2 - Non Demand	$ 0.00230	$ 0.00256	$ 0.00255	$ 0.00258
S.C. No. 2 - Primary Demand	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00011	$ 0.00011	$ 0.00011	$ 0.00012
S.C. No. 3 - Large Power Primary	$ -	$ -	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00427	$ 0.00444	$ 0.00445	$ 0.00445
S.C. No. 6 - Residential Time-of-Use	$ 0.00075	$ 0.00072	$ 0.00072	$ 0.00072
S.C. No. 8 - Street Lighting	$ 0.00012	$ 0.00017	$ 0.00018	$ 0.00018
S.C. No. 9 - Traffic Signals	$ 0.00116	$ 0.00114	$ 0.00118	$ 0.00122
S.C. No. 13 - Substation	$ -	$ -	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -	$ -	$ -
MFC Supply Charge per kWh				
S.C. No. 1 - Residential	$ 0.00236	$ 0.00305	$ 0.00309	$ 0.00315
S.C. No. 2 - Non Demand	$ 0.00332	$ 0.00433	$ 0.00431	$ 0.00436
S.C. No. 2 - Primary Demand	$ 0.00001	$ 0.00002	$ 0.00002	$ 0.00002
S.C. No. 2 - Secondary Demand	$ 0.00016	$ 0.00019	$ 0.00019	$ 0.00019
S.C. No. 3 - Large Power Primary	$ -	$ -	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.00618	$ 0.00750	$ 0.00752	$ 0.00752
S.C. No. 6 - Residential Time-of-Use	$ 0.00108	$ 0.00121	$ 0.00121	$ 0.00121
S.C. No. 8 - Street Lighting	$ 0.00018	$ 0.00028	$ 0.00030	$ 0.00031
S.C. No. 9 - Traffic Signals	$ 0.00167	$ 0.00193	$ 0.00200	$ 0.00207
S.C. No. 13 - Substation	$ -	$ -	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -	$ -	$ -

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Proposed Electric Bill Credit

		Current Rates	12 Months Ending Jun-19 Rate Year 1	12 Months Ending Jun-20 Rate Year 2	12 Months Ending Jun-21 Rate Year 3
S.C. No. 1 - Residential	per kWh	$ (0.00073)	$ (0.00190)	$ (0.00307)	$ (0.00381)
S.C. No. 2 - Non Demand	per kWh	$ (0.00093)	$ (0.00234)	$ (0.00402)	$ (0.00496)
S.C. No. 2 - Primary Demand	per kWh	$ (0.00013)	$ (0.00043)	$ (0.00056)	$ (0.00068)
S.C. No. 2 - Secondary Demand	per kWh	$ (0.00015)	$ (0.00100)	$ (0.00128)	$ (0.00157)
S.C. No. 3 - Large Power Primary	per kW	$ (0.06000)	$ (0.19000)	$ (0.25000)	$ (0.30000)
S.C. No. 5 - Area Lighting	per kWh	$ (0.00143)	$ (0.00308)	$ (0.00512)	$ (0.00634)
S.C. No. 6 - Residential Time-of-Use	per kWh	$ (0.00025)	$ (0.00116)	$ (0.00147)	$ (0.00179)
S.C. No. 8 - Street Lighting	per kWh	$ (0.00128)	$ (0.00846)	$ (0.01065)	$ (0.01369)
S.C. No. 9 - Traffic Signals	per kWh	$ (0.00039)	$ (0.00127)	$ (0.00175)	$ (0.00226)
S.C. No. 13 - Substation	per kW	$ (0.06000)	$ (0.25000)	$ (0.36000)	$ (0.46000)
S.C. No. 13 - Transmission	per kW	$ (0.03000)	$ (0.08000)	$ (0.11000)	$ (0.15000)

Central Hudson Gas & Electric Corporation
Electric Energy Efficiency Base Rate Design

Twelve Months Ending June 30, 2019

Energy Efficiency Allocation	Summer CP kW	RNY/EZ kW	Demand = 12.70% Summer CP %	Allocation	RY MWh	RNY/EZ MWh	Energy = 87.30% MWh %	Allocation	Total Allocator
SC 1 Residential	577,649		58.12%	7.38%	1,941,012		46.50%	40.59%	47.97%
SC 2 Non Demand	29,918		3.01%	0.38%	157,002		3.76%	3.28%	3.67%
SC 2 Secondary	322,168	86	32.41%	4.12%	1,385,548	451	33.18%	28.96%	33.08%
SC 2 Primary	8,188	716	0.75%	0.10%	215,254	3,581	5.07%	4.43%	4.52%
SC 3 Primary	26,151	260	2.61%	0.33%	271,759	1,771	6.47%	5.65%	5.98%
SC 5 Area Lighting	-		0.00%	0.00%	12,333		0.30%	0.26%	0.26%
SC 6 Residential TOU	1,873		0.19%	0.02%	19,030		0.46%	0.40%	0.42%
SC 8 Street Lighting	-		0.00%	0.00%	17,260		0.41%	0.36%	0.36%
SC 9 Traffic Signals	272		0.03%	0.00%	2,370		0.06%	0.05%	0.05%
SC 13 Substation	14,512	5,980	0.86%	0.11%	153,752	43,369	2.64%	2.31%	2.42%
SC 13 Transmission	77,977	57,840	2.03%	0.26%	711,174	662,630	1.16%	1.02%	1.27%
Total	1,058,708	64,882	100.00%	12.70%	4,886,494	711,802	100.00%	87.30%	100.00%

	Total Allocator	$ 9,773,000 Allocation	All kW	RNY/EZ kW	Non-RNY/EZ kW	Not Collected	Non-RNY/EZ $/kW	Base Rates $/kW	Total $/kW	Recovery All kW	Recovery RNY/EZ Credit	Recovery Total	Base Rate
SC 1 Residential	47.97%	$ 4,688,292										$ 4,688,292	$ 4,688,292
SC 2 Non Demand	3.67%	$ 358,241										$ 358,241	$ 358,241
SC 2 Secondary	33.08%	$ 3,232,929	4,364,394	1,032	4,363,362	$ 764	$ -	$ 0.741	$ 0.741	$ 3,234,016	$ (765)	$ 3,233,251	$ 3,234,016
SC 2 Primary	4.52%	$ 441,897	557,701	8,592	549,109	$ 6,808	$ 0.012	$ 0.792	$ 0.804	$ 448,392	$ (6,908)	$ 441,484	$ 448,392
SC 3 Primary	5.98%	$ 584,086	602,460	3,120	599,340	$ 3,025	$ 0.005	$ 0.970	$ 0.975	$ 587,399	$ (3,042)	$ 584,357	$ 587,399
SC 5 Area Lighting	0.26%	$ 25,169										$ 25,169	$ 25,169
SC 6 Residential TOU	0.42%	$ 41,239										$ 41,239	$ 41,239
SC 8 Street Lighting	0.36%	$ 35,236										$ 35,236	$ 35,236
SC 9 Traffic Signals	0.05%	$ 5,198										$ 5,198	$ 5,198
SC 13 Substation	2.42%	$ 236,243	220,025	71,760	148,265	$ 77,049	$ 0.520	$ 1.074	$ 1.594	$ 350,720	$ (114,385)	$ 236,335	$ 350,720
SC 13 Transmission	1.27%	$ 124,371	1,175,412	786,219	389,193	$ 83,190	$ 0.214	$ 0.106	$ 0.320	$ 376,132	$ (251,590)	$ 124,542	$ 376,132
Total	100.00%	$ 9,772,901										$ 9,773,344	

Central Hudson Gas & Electric Corporation
Electric Energy Efficiency Base Rate Design

Twelve Months Ending June 30, 2020

	Demand = 12.70%				Energy = 87.30%				
Energy Efficiency Allocation	Summer CP kW	RNY/EZ kW	Summer CP %	Allocation	RY MWh	RNY/EZ MWh	MWh %	Allocation	**Total Allocator**
SC 1 Residential	577,649		57.79%	7.34%	1,913,313		43.55%	38.02%	45.36%
SC 2 Non Demand	29,918		2.99%	0.38%	157,785		3.59%	3.14%	3.52%
SC 2 Secondary	322,168	86	32.22%	4.09%	1,367,162	451	31.11%	27.16%	31.25%
SC 2 Primary	8,188	716	0.75%	0.09%	212,237	3,581	4.75%	4.15%	4.24%
SC 3 Primary	26,151	260	2.59%	0.33%	268,176	590	6.09%	5.32%	5.65%
SC 5 Area Lighting	-		0.00%	0.00%	12,300		0.28%	0.24%	0.24%
SC 6 Residential TOU	1,873		0.19%	0.02%	19,030		0.43%	0.38%	0.40%
SC 8 Street Lighting	-		0.00%	0.00%	16,240		0.37%	0.32%	0.32%
SC 9 Traffic Signals	272		0.03%	0.00%	2,286		0.05%	0.05%	0.05%
SC 13 Substation	14,512	2,480	1.20%	0.15%	162,292	15,709	3.34%	2.91%	3.07%
SC 13 Transmission	77,977	55,518	2.25%	0.29%	711,174	428,460	6.44%	5.62%	5.90%
Total	1,058,708	59,060	100.00%	12.70%	4,841,995	448,791	100.00%	87.30%	100.00%

	Total	**$ 9,773,000**			**Non-RNY/EZ**	**Not**	**Non-RNY/EZ**	**Base Rates**	**Total**	**Recovery**				**Change**
	Allocator	**Allocation**	**All kW**	**RNY/EZ kW**	**kW**	**Collected**	**$/kW**	**$/kW**	**$/kW**	**All kW**	**RNY/EZ Credit**	**Total**	**Base Rate**	**from RY1**
SC 1 Residential	45.36%	$ 4,432,993										$ 4,432,993	$ 4,432,993	$ (255,299)
SC 2 Non Demand	3.52%	$ 343,612										$ 343,612	$ 343,612	$ (14,629)
SC 2 Secondary	31.25%	$ 3,054,157	4,306,321	1,032	4,305,289	$ 732	$ -	$ 0.709	$ 0.709	$ 3,053,182	$ (732)	$ 3,052,450	$ 3,053,182	$ (180,069)
SC 2 Primary	4.24%	$ 414,533	549,888	8,592	541,296	$ 6,477	$ 0.012	$ 0.754	$ 0.766	$ 421,214	$ (6,581)	$ 414,633	$ 421,214	$ (20,270)
SC 3 Primary	5.65%	$ 551,820	594,512	1,040	593,472	$ 965	$ 0.002	$ 0.928	$ 0.930	$ 552,896	$ (967)	$ 551,929	$ 552,896	$ (31,461)
SC 5 Area Lighting	0.24%	$ 23,889										$ 23,889	$ 23,889	$ (1,280)
SC 6 Residential TOU	0.40%	$ 39,264										$ 39,264	$ 39,264	$ (1,975)
SC 8 Street Lighting	0.32%	$ 31,568										$ 31,568	$ 31,568	$ (3,668)
SC 9 Traffic Signals	0.05%	$ 4,772										$ 4,772	$ 4,772	$ (426)
SC 13 Substation	3.07%	$ 299,651	228,572	29,760	198,812	$ 39,014	$ 0.196	$ 1.311	$ 1.507	$ 344,458	$ (44,848)	$ 299,610	$ 344,458	$ 108,123
SC 13 Transmission	5.90%	$ 576,912	1,175,412	666,219	509,193	$ 326,992	$ 0.642	$ 0.491	$ 1.133	$ 1,331,742	$ (754,826)	$ 576,916	$ 1,331,742	$ 1,207,200
Total	100.00%	$ 9,773,171										$ 9,771,636		

Central Hudson Gas & Electric Corporation
Electric Energy Efficiency Base Rate Design

Twelve Months Ending June 30, 2021

	Demand = 12.70%				Energy = 87.30%				
Energy Efficiency Allocation	Summer CP kW	RNY/EZ kW	Summer CP %	Allocation	RY MWh	RNY/EZ MWh	MWh %	Allocation	**Total Allocator**
SC 1 Residential	577,649		54.73%	6.95%	1,880,697		39.48%	34.4625480%	41.41%
SC 2 Non Demand	29,918		2.84%	0.36%	155,943		3.27%	2.86%	3.22%
SC 2 Secondary	322,168	86	30.52%	3.88%	1,348,493	451	28.30%	24.70%	28.58%
SC 2 Primary	8,188	716	0.71%	0.09%	208,837	298	4.38%	3.82%	3.91%
SC 3 Primary	26,151	-	2.48%	0.31%	264,098	-	5.54%	4.84%	5.15%
SC 5 Area Lighting	-		0.00%	0.00%	12,300		0.26%	0.23%	0.23%
SC 6 Residential TOU	1,873		0.18%	0.02%	19,030		0.40%	0.35%	0.37%
SC 8 Street Lighting	-		0.00%	0.00%	15,560		0.33%	0.29%	0.29%
SC 9 Traffic Signals	272		0.03%	0.00%	2,208		0.05%	0.04%	0.04%
SC 13 Substation	14,512	2,480	1.14%	0.14%	162,318	15,709	3.08%	2.69%	2.83%
SC 13 Transmission	77,977	-	7.39%	0.94%	711,174	-	14.93%	13.03%	13.97%
Total	1,058,708	3,282	100.00%	12.70%	4,780,658	16,458	100.00%	87.30%	100.00%

	Total Allocator	**Allocation**	**All kW**	**RNY/EZ kW**	**Non-RNY/EZ kW**	**Not Collected**	**Non-RNY/EZ $/kW**	**Base Rates $/kW**	**Total $/kW**	**Recovery** All kW	**Recovery** RNY/EZ Credit	**Recovery** Total	**Base Rate**	**Change from RY2**
		$ 9,773,000												
SC 1 Residential	41.41%	$ 4,047,330										$ 4,047,330	$ 4,047,330	$ (385,663)
SC 2 Non Demand	3.22%	$ 314,434										$ 314,434	$ 314,434	$ (29,178)
SC 2 Secondary	28.58%	$ 2,792,849	4,247,449	1,032	4,246,417	$ 679	$ -	$ 0.658	$ 0.66	$ 2,794,821	$ (679)	$ 2,794,142	$ 2,794,821	$ (257,629)
SC 2 Primary	3.91%	$ 382,226	541,081	716	540,365	$ 506	$ 0.001	$ 0.706	$ 0.71	$ 382,544	$ (506)	$ 382,038	$ 382,544	$ (32,089)
SC 3 Primary	5.15%	$ 503,675	585,472	-	585,472	$ -	$ -	$ 0.860	$ 0.86	$ 503,506	$ -	$ 503,506	$ 503,506	$ (48,423)
SC 5 Area Lighting	0.23%	$ 22,012										$ 22,012	$ 22,012	$ (1,877)
SC 6 Residential TOU	0.37%	$ 36,239										$ 36,239	$ 36,239	$ (3,025)
SC 8 Street Lighting	0.29%	$ 27,899										$ 27,899	$ 27,899	$ (3,669)
SC 9 Traffic Signals	0.04%	$ 4,247										$ 4,247	$ 4,247	$ (525)
SC 13 Substation	2.83%	$ 276,674	228,597	29,760	198,837	$ 36,019	$ 0.181	$ 1.210	$ 1.39	$ 317,978	$ (41,396)	$ 276,582	$ 317,978	$ 18,368
SC 13 Transmission	13.97%	$ 1,365,244	1,175,412	-	1,175,412	$ -	$ -	$ 1.162	$ 1.16	$ 1,365,829	$ -	$ 1,365,829	$ 1,365,829	$ 788,913
Total	100.00%	$ 9,772,829										$ 9,774,258		

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Gas Billing Determinants

		Rate Year 1	Rate Year 2	Rate Year 3
S.C. No. 1 & 12 Res. Heat	Block 1 - Customer Months	759,817	771,592	783,364
	Block 1 - Mcf - Included in Customer Charge	146,181	148,439	150,705
	Block 2 - Mcf	2,478,177	2,516,533	2,554,888
	Block 3 - Mcf	3,140,688	3,189,267	3,237,821
S.C. No. 1 & 12 Res. Non-Heat	Block 1 - Customer Months	81,665	78,901	76,138
	Block 1 - Mcf - Included in Customer Charge	13,187	12,743	12,298
	Block 2 - Mcf	87,540	84,584	81,627
	Block 3 - Mcf	46,578	45,003	43,426
S.C. No. 2, 6 & 13 Heat	Block 1 - Customer Months	127,840	129,805	131,772
	Block 1 - Mcf - Included in Customer Charge	20,798	21,108	21,367
	Block 2 - Mcf	707,435	717,802	726,410
	Block 3 - Mcf	3,865,305	3,921,136	3,967,253
	Block 4 - Mcf	1,326,859	1,345,983	1,361,736
S.C. No. 2, 6 & 13 Non-Heat	Block 1 - Customer Months	13,898	13,723	13,545
	Block 1 - Mcf - Included in Customer Charge	2,373	2,356	2,329
	Block 2 - Mcf	73,264	72,724	71,745
	Block 3 - Mcf	332,480	330,094	325,639
	Block 4 - Mcf	474,244	470,778	464,512
S.C. No. 11 Transmission				
	Block 1 - Customer Months	24	24	24
	Block 1 - Mcf - Included in Customer Charge	2,400	2,400	2,400
	Block 2 - Mcf	1,000,085	1,000,085	1,000,085
	MDQ	102,576	102,576	102,576
S.C. No. 11 Distribution				
	Block 1 - Customer Months	12	12	12
	Block 1 - Mcf - Included in Customer Charge	1,200	1,200	1,200
	Block 2 - Mcf	48,947	48,947	48,947
	MDQ	4,236	4,236	4,236
S.C. No. 11 - DLM	Block 1 - Customer Months	12	12	12
	Block 1 - Mcf - Included in Customer Charge	1,200	1,200	1,200
	Block 2 - Mcf	721,557	721,557	721,557
	MDQ	58,800	58,800	58,800
Interdepartmental (S.C. No. 2)	Block 4 - Mcf	24,000	24,000	24,000

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Proposed Monthly Gas Base Delivery Rates

			Current Rates	Rate Year 1 July 1, 2018	Rate Year 2 July 1, 2019	Rate Year 3 July 1, 2020
S.C. No. 1 & 12						
	Billing Block 1	First 2 Ccf	$ 26.00	$ 25.00	$ 24.50	$ 24.25
	Billing Block 2 per Ccf	Next 48 Ccf	$ 0.9904	$ 1.1050	$ 1.2228	$ 1.3593
	Billing Block 3 per Ccf	Additional	$ 0.4542	$ 0.5060	$ 0.5621	$ 0.6248
S.C. No. 2, 6 & 13						
	Billing Block 1	First 2 Ccf	$ 39.00	$ 39.00	$ 39.00	$ 39.00
	Billing Block 2 per Ccf	Next 98 Ccf	$ 0.5494	$ 0.5836	$ 0.6340	$ 0.6919
	Billing Block 3 per Ccf	Next 4900 Ccf	$ 0.3262	$ 0.3464	$ 0.3764	$ 0.4129
	Billing Block 4 per Ccf	Additional	$ 0.2656	$ 0.2819	$ 0.3057	$ 0.3345
S.C. No. 11 Transmission						
Annual x<300k Mcf	Billing Block 1	First 50,000 Ccf	$ 7,500.00	N/A	N/A	N/A
	Billing Block 2 per Ccf	Additional	$ 0.0298	N/A	N/A	N/A
Annual 300k<x<800k Mcf	Billing Block 1	First 100,000 Ccf	$ 38,200.00	N/A	N/A	N/A
	Billing Block 2 per Ccf	Additional	$ 0.0447	N/A	N/A	N/A
Annual x>800k Mcf	Billing Block 1	First 300,000 Ccf	$ 64,300.00	N/A	N/A	N/A
	Billing Block 2 per Ccf	Additional	$ 0.0391	N/A	N/A	N/A
S.C. No. 11 Distribution						
Annual x<100k Mcf	Billing Block 1	First 40,000 Ccf	$ 7,500.00	N/A	N/A	N/A
	Billing Block 2 per Ccf	Additional	$ 0.0639	N/A	N/A	N/A
Annual x>=100k Mcf	Billing Block 1	First 70,000 Ccf	$ 17,200.00	N/A	N/A	N/A
	Billing Block 2 per Ccf	Additional	$ 0.0612	N/A	N/A	N/A
S.C. No. 11 DLM	Billing Block 1	First 300,000 Ccf	$ 50,600.00	N/A	N/A	N/A
	Billing Block 2 per Ccf	Additional	$ 0.0599	N/A	N/A	N/A
S.C. No. 11 Transmission*	Customer Charge	First 1,000 Ccf	N/A	$ 3,000.00	$ 3,300.00	$ 3,600.00
	Volumetric Charge per Ccf	Additional	N/A	$ 0.0148	$ 0.0157	$ 0.0166
	MDQ	Per Mcf of MDQ per Month	N/A	$ 7.02	$ 7.46	$ 8.02
S.C. No. 11 Distribution*	Customer Charge	First 1,000 Ccf	N/A	$ 1,000.00	$ 1,100.00	$ 1,200.00
	Volumetric Charge per Ccf	Additional	N/A	$ 0.0312	$ 0.0332	$ 0.0357
	MDQ	Per Mcf of MDQ per Month	N/A	$ 16.66	$ 17.65	$ 18.90
S.C. No. 11 DLM*	Customer Charge	First 1,000 Ccf	N/A	$ 6,000.00	$ 6,400.00	$ 6,800.00
	Volumetric Charge per Ccf	Additional	N/A	$ 0.0198	$ 0.0212	$ 0.0226
	MDQ	Per Mcf of MDQ per Month	N/A	$ 11.73	$ 12.48	$ 13.44
S.C. No. 11 EG	Customer Charge		$ 1,200.00	$ 1,500.00	$ 1,600.00	$ 1,700.00
	MDQ	Per Mcf of MDQ per Month	$ 9.25	$ 9.88	$ 10.78	$ 11.84

* Please refer to Section X.B.2 on S.C. No. 11 Rate Design.

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Gas Commodity Related Merchant Function Charges

		Current Rates	Rate Year 1 July 1, 2018	Rate Year 2 July 1, 2019	Rate Year 3 July 1, 2020
MFC Administration Charge per Ccf					
MFC-1	1, 12 & 16	$ 0.00434	$ 0.00697	$ 0.00687	$ 0.00678
MFC-2	2, 6, 13 & 15	$ 0.00419	$ 0.00764	$ 0.00755	$ 0.00749
MFC Supply Charge per Ccf					
MFC-1	1, 12 & 16	$ 0.01297	$ 0.01908	$ 0.01881	$ 0.01855
MFC-2	2, 6, 13 & 15	$ 0.01251	$ 0.02091	$ 0.02067	$ 0.02050

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Summary of Proposed Monthly Gas Bill Credit Rates

Applicable to S.C. No.		$/Ccf Rate Year 1 July 1, 2018	$/Ccf Rate Year 2 July 1, 2019	$/Ccf Rate Year 3 July 1, 2020
1, 12 & 16	$/Ccf	$ (0.03950)	$ (0.04454)	$ (0.04400)
2, 6, 13 & 15	$/Ccf	$ (0.01604)	$ (0.01820)	$ (0.01799)
SC 11 Transmission	$/Ccf	$ (0.00300)	$ (0.00370)	$ (0.00366)
SC 11 Distribution	$/Ccf	$ (0.00749)	$ (0.00796)	$ (0.00733)
SC 11 - DLM	$/Ccf	$ (0.00554)	$ (0.00492)	$ (0.00486)

Gas bill credit rates reflect rate moderation as described in Section IV.D and Danskmammer credits as described in Section IX.A

Central Hudson Gas & Electric Corporation
Electric Residential Typical Monthly Bill
Rate Year 1

Rates as of January 3, 2018 (First Billing Batch in January)

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Avg kWh	**625**	**625**	**625**	**625**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 24.00	$ 21.00	$ 24.00	$ 21.00	
Energy Delivery $/kWh					
Delivery Chrg	$0.06586	$0.07563	$0.06586	$0.07563	
System Benefits Chrg	$0.00899	$0.00698	$0.00899	$0.00698	
MFC Admin Chrg	$0.00163	$0.00180	$0.00163	$0.00180	
Transition Adj Chrg	$0.00017	$0.00000	$0.00017	$0.00000	
Electric Bill Credit	($0.00073)	($0.00190)	($0.00073)	($0.00190)	
Purchased Power Adjustment	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous Charges	($0.00362)	($0.00362)	($0.00362)	($0.00362)	
MFC Supply Chrg	$0.00257	$0.00305	$0.00257	$0.00305	
MPC	$0.06346	$0.06346	$0.06346	$0.06346	
MPA	($0.00459)	($0.00459)	($0.00459)	($0.00459)	
Rev Tax Factor:					
Weighted Rev Tax- Commodity	0.314%	0.314%	0.314%	0.314%	
Weighted Rev Tax- Delivery	2.314%	2.314%	2.314%	2.314%	
CHG&E Bill					
Basic Service Charge	$24.57	$21.50	$24.57	$21.50	
Energy Delivery					
Delivery	$42.14	$48.39	$42.14	$48.39	
MFC Admin Chrg	$1.04	$1.15	$1.04	$1.15	
Transition Adj Chrg	$0.11	$0.00	$0.11	$0.00	
EBC	($0.47)	($1.22)	($0.47)	($1.22)	
SBC	$5.75	$4.47	$5.75	$4.47	
Delivery Subtotal w/ Revenue Tax	$73.14	$74.29	$73.14	$74.29	
Energy Supply					
PPA	$0.00	$0.00	$0.00	$0.00	
MISC	($2.27)	($2.27)	($2.27)	($2.27)	
MPC	$39.79	$39.79	$39.79	$39.79	
MPA	($2.88)	($2.88)	($2.88)	($2.88)	
MFC Supply Chrg	$1.64	$1.95	$1.64	$1.95	
Energy Subtotal w/ Revenue Tax	$36.28	$36.59	$36.28	$36.59	
Low Income Bill Discount	$0.00	$0.00	($19.00)	($19.00)	(Tier 1 Discount)
Total Bill	**$109.42**	**$110.88**	**$90.42**	**$91.88**	

$ Total Bill Increase w/ Rate Moderation	$1.46	$1.46
% Total Bill Increase w/ Rate Moderation	1.33%	1.61%
$ Total Bill Increase w/out Rate Moderation	$2.68	$2.68
% Total Bill Increase w/out Rate Moderation	2.45%	2.96%

* SBC rates reflect inclusion of Energy Efficiency in base rates

Central Hudson Gas & Electric Corporation
Electric Residential Typical Monthly Bill
Rate Year 1

Monthly kWh	Bill at Current Rates		Bill at Proposed Rates		Over Current Amount		%
3	$	24.98	$	21.93	$	(3.05)	-12.2%
10	$	25.93	$	22.93	$	(3.00)	-11.6%
20	$	27.28	$	24.36	$	(2.93)	-10.7%
30	$	28.64	$	25.79	$	(2.85)	-10.0%
40	$	30.00	$	27.22	$	(2.78)	-9.3%
50	$	31.36	$	28.65	$	(2.71)	-8.6%
80	$	35.43	$	32.94	$	(2.49)	-7.0%
90	$	36.79	$	34.37	$	(2.42)	-6.6%
100	$	38.15	$	35.80	$	(2.35)	-6.2%
125	$	41.54	$	39.37	$	(2.17)	-5.2%
150	$	44.93	$	42.95	$	(1.99)	-4.4%
175	$	48.33	$	46.52	$	(1.80)	-3.7%
200	$	51.72	$	50.10	$	(1.62)	-3.1%
250	$	58.51	$	57.25	$	(1.26)	-2.2%
300	$	65.30	$	64.40	$	(0.90)	-1.4%
350	$	72.09	$	71.55	$	(0.54)	-0.7%
400	$	78.88	$	78.70	$	(0.18)	-0.2%
500	$	92.46	$	93.00	$	0.55	0.6%
750	$	126.40	$	128.76	$	2.36	1.9%
1,000	$	160.34	$	164.51	$	4.17	2.6%
1,500	$	228.23	$	236.01	$	7.79	3.4%
2,000	$	296.12	$	307.52	$	11.40	3.9%
3,000	$	431.89	$	450.53	$	18.64	4.3%
5,000	$	703.44	$	736.55	$	33.12	4.7%
10,000	$	1,382.30	$	1,451.61	$	69.30	5.0%
15,000	$	2,061.17	$	2,166.66	$	105.49	5.1%
20,000	$	2,740.03	$	2,881.71	$	141.68	5.2%
25,000	$	3,418.90	$	3,596.77	$	177.87	5.2%
30,000	$	4,097.77	$	4,311.82	$	214.05	5.2%
35,000	$	4,776.63	$	5,026.88	$	250.24	5.2%
40,000	$	5,455.50	$	5,741.93	$	286.43	5.3%
55,000	$	7,492.10	$	7,887.09	$	394.99	5.3%
75,000	$	10,207.57	$	10,747.31	$	539.74	5.3%
190,000	$	25,821.50	$	27,193.55	$	1,372.05	5.3%
205,000	$	27,858.10	$	29,338.71	$	1,480.61	5.3%

Central Hudson Gas & Electric Corporation
Electric Residential Typical Monthly Bill
Rate Year 2

Rates as of January 3, 2018 (First Billing Batch in January)

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Avg kWh	**625**	**625**	**625**	**625**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 21.00	$ 20.00	$ 21.00	$ 20.00	
Energy Delivery $/kWh					
Delivery Chrg	$0.07563	$0.08349	$0.07563	$0.08349	
System Benefits Chrg	$0.00698	$0.00698	$0.00698	$0.00698	
MFC Admin Chrg	$0.00180	$0.00183	$0.00180	$0.00183	
Transition Adj Chrg	$0.00000	$0.00000	$0.00000	$0.00000	
Electric Bill Credit	($0.00190)	($0.00307)	($0.00190)	($0.00307)	
Purchased Power Adjustment	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous Charges	($0.00362)	($0.00362)	($0.00362)	($0.00362)	
MFC Supply Chrg	$0.00305	$0.00309	$0.00305	$0.00309	
MPC	$0.06346	$0.06346	$0.06346	$0.06346	
MPA	($0.00459)	($0.00459)	($0.00459)	($0.00459)	
Rev Tax Factor:					
Weighted Rev Tax- Commodity	0.314%	0.314%	0.314%	0.314%	
Weighted Rev Tax- Delivery	2.314%	2.314%	2.314%	2.314%	
CHG&E Bill					
Basic Service Charge	$21.50	$20.47	$21.50	$20.47	
Energy Delivery					
Delivery	$48.39	$53.42	$48.39	$53.42	
MFC Admin Chrg	$1.15	$1.17	$1.15	$1.17	
Transition Adj Chrg	$0.00	$0.00	$0.00	$0.00	
EBC	($1.22)	($1.96)	($1.22)	($1.96)	
SBC	$4.47	$4.47	$4.47	$4.47	
Delivery Subtotal w/ Revenue Tax	$74.29	$77.57	$74.29	$77.57	
Energy Supply					
PPA	$0.00	$0.00	$0.00	$0.00	
MISC	($2.27)	($2.27)	($2.27)	($2.27)	
MPC	$39.79	$39.79	$39.79	$39.79	
MPA	($2.88)	($2.88)	($2.88)	($2.88)	
MFC Supply Chrg	$1.95	$1.98	$1.95	$1.98	
Energy Subtotal w/ Revenue Tax	$36.59	$36.62	$36.59	$36.62	
Low Income Bill Discount	$0.00	$0.00	($19.00)	($19.00)	(Tier 1 Discount)
Total Bill	**$110.88**	**$114.19**	**$91.88**	**$95.19**	

$ Total Bill Increase w/ Rate Moderation		$3.31		$3.31
% Total Bill Increase w/ Rate Moderation		2.99%		3.60%
$ Total Bill Increase w/out Rate Moderation		$5.27		$5.27
% Total Bill Increase w/out Rate Moderation		4.75%		5.74%

Central Hudson Gas & Electric Corporation
Electric Residential Typical Monthly Bill
Rate Year 2

Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	%
3	$ 21.93	$ 20.92	$ (1.00)	-4.6%
10	$ 22.93	$ 21.97	$ (0.95)	-4.2%
20	$ 24.36	$ 23.47	$ (0.89)	-3.6%
30	$ 25.79	$ 24.97	$ (0.82)	-3.2%
40	$ 27.22	$ 26.47	$ (0.75)	-2.7%
50	$ 28.65	$ 27.97	$ (0.68)	-2.4%
80	$ 32.94	$ 32.47	$ (0.47)	-1.4%
90	$ 34.37	$ 33.97	$ (0.40)	-1.2%
100	$ 35.80	$ 35.47	$ (0.33)	-0.9%
125	$ 39.37	$ 39.22	$ (0.16)	-0.4%
150	$ 42.95	$ 42.96	$ 0.01	0.0%
175	$ 46.52	$ 46.71	$ 0.19	0.4%
200	$ 50.10	$ 50.46	$ 0.36	0.7%
250	$ 57.25	$ 57.96	$ 0.71	1.2%
300	$ 64.40	$ 65.45	$ 1.05	1.6%
350	$ 71.55	$ 72.95	$ 1.40	2.0%
400	$ 78.70	$ 80.45	$ 1.74	2.2%
500	$ 93.00	$ 95.44	$ 2.44	2.6%
750	$ 128.76	$ 132.92	$ 4.17	3.2%
1,000	$ 164.51	$ 170.40	$ 5.90	3.6%
1,500	$ 236.01	$ 245.37	$ 9.36	4.0%
2,000	$ 307.52	$ 320.34	$ 12.82	4.2%
3,000	$ 450.53	$ 470.27	$ 19.74	4.4%
5,000	$ 736.55	$ 770.13	$ 33.58	4.6%
10,000	$ 1,451.61	$ 1,519.78	$ 68.18	4.7%
15,000	$ 2,166.66	$ 2,269.44	$ 102.78	4.7%
20,000	$ 2,881.71	$ 3,019.09	$ 137.38	4.8%
25,000	$ 3,596.77	$ 3,768.75	$ 171.98	4.8%
30,000	$ 4,311.82	$ 4,518.40	$ 206.58	4.8%
35,000	$ 5,026.88	$ 5,268.06	$ 241.18	4.8%
40,000	$ 5,741.93	$ 6,017.71	$ 275.78	4.8%
55,000	$ 7,887.09	$ 8,266.67	$ 379.58	4.8%
75,000	$ 10,747.31	$ 11,265.29	$ 517.99	4.8%
190,000	$ 27,193.55	$ 28,507.35	$ 1,313.80	4.8%
205,000	$ 29,338.71	$ 30,756.31	$ 1,417.60	4.8%

Central Hudson Gas & Electric Corporation
Electric Residential Typical Monthly Bill
Rate Year 3

Rates as of January 3, 2018 (First Billing Batch in January)

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Avg kWh	**625**	**625**	**625**	**625**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 20.00	$ 19.50	$ 20.00	$ 19.50	
Energy Delivery $/kWh					
Delivery Chrg	$0.08349	$0.09283	$0.08349	$0.09283	
System Benefits Chrg	$0.00698	$0.00698	$0.00698	$0.00698	
MFC Admin Chrg	$0.00183	$0.00186	$0.00183	$0.00186	
Transition Adj Chrg	$0.00000	$0.00000	$0.00000	$0.00000	
Electric Bill Credit	($0.00307)	($0.00381)	($0.00307)	($0.00381)	
Purchased Power Adjustment	$0.00000	$0.00000	$0.00000	$0.00000	
Miscellaneous Charges	($0.00362)	($0.00362)	($0.00362)	($0.00362)	
MFC Supply Chrg	$0.00309	$0.00315	$0.00309	$0.00315	
MPC	$0.06346	$0.06346	$0.06346	$0.06346	
MPA	($0.00459)	($0.00459)	($0.00459)	($0.00459)	
Rev Tax Factor:					
Weighted Rev Tax- Commodity	0.314%	0.314%	0.314%	0.314%	
Weighted Rev Tax- Delivery	2.314%	2.314%	2.314%	2.314%	
CHG&E Bill					
Basic Service Charge	$20.47	$19.96	$20.47	$19.96	
Energy Delivery					
Delivery	$53.42	$59.39	$53.42	$59.39	
MFC Admin Chrg	$1.17	$1.19	$1.17	$1.19	
Transition Adj Chrg	$0.00	$0.00	$0.00	$0.00	
EBC	($1.96)	($2.44)	($1.96)	($2.44)	
SBC	$4.47	$4.47	$4.47	$4.47	
Delivery Subtotal w/ Revenue Tax	$77.57	$82.57	$77.57	$82.57	
Energy Supply					
PPA	$0.00	$0.00	$0.00	$0.00	
MISC	($2.27)	($2.27)	($2.27)	($2.27)	
MPC	$39.79	$39.79	$39.79	$39.79	
MPA	($2.88)	($2.88)	($2.88)	($2.88)	
MFC Supply Chrg	$1.98	$2.02	$1.98	$2.02	
Energy Subtotal w/ Revenue Tax	$36.62	$36.66	$36.62	$36.66	
Low Income Bill Discount	$0.00	$0.00	($19.00)	($19.00)	(Tier 1 Discount)
Total Bill	**$114.19**	**$119.23**	**$95.19**	**$100.23**	

$ Total Bill Increase w/ Rate Moderation	$5.04	$5.04
% Total Bill Increase w/ Rate Moderation	4.41%	5.29%
$ Total Bill Increase w/out Rate Moderation	$7.48	$7.48
% Total Bill Increase w/out Rate Moderation	6.55%	7.86%

Appendix N Sheet 6 of 23

Central Hudson Gas & Electric Corporation
Electric Residential Typical Monthly Bill
Rate Year 3

Monthly kWh	Bill at Current Rates	Bill at Proposed Rates	Over Current Amount	%
3	$ 20.92	$ 20.44	$ (0.49)	-2.3%
10	$ 21.97	$ 21.55	$ (0.42)	-1.9%
20	$ 23.47	$ 23.14	$ (0.33)	-1.4%
30	$ 24.97	$ 24.73	$ (0.24)	-1.0%
40	$ 26.47	$ 26.31	$ (0.16)	-0.6%
50	$ 27.97	$ 27.90	$ (0.07)	-0.2%
80	$ 32.47	$ 32.67	$ 0.20	0.6%
90	$ 33.97	$ 34.26	$ 0.29	0.9%
100	$ 35.47	$ 35.84	$ 0.38	1.1%
125	$ 39.22	$ 39.82	$ 0.60	1.5%
150	$ 42.96	$ 43.79	$ 0.82	1.9%
175	$ 46.71	$ 47.76	$ 1.04	2.2%
200	$ 50.46	$ 51.73	$ 1.27	2.5%
250	$ 57.96	$ 59.67	$ 1.71	3.0%
300	$ 65.45	$ 67.61	$ 2.16	3.3%
350	$ 72.95	$ 75.55	$ 2.60	3.6%
400	$ 80.45	$ 83.49	$ 3.05	3.8%
500	$ 95.44	$ 99.38	$ 3.94	4.1%
750	$ 132.92	$ 139.08	$ 6.16	4.6%
1,000	$ 170.40	$ 178.79	$ 8.38	4.9%
1,500	$ 245.37	$ 258.20	$ 12.83	5.2%
2,000	$ 320.34	$ 337.62	$ 17.28	5.4%
3,000	$ 470.27	$ 496.44	$ 26.18	5.6%
5,000	$ 770.13	$ 814.10	$ 43.97	5.7%
10,000	$ 1,519.78	$ 1,608.23	$ 88.45	5.8%
15,000	$ 2,269.44	$ 2,402.36	$ 132.93	5.9%
20,000	$ 3,019.09	$ 3,196.50	$ 177.41	5.9%
25,000	$ 3,768.75	$ 3,990.63	$ 221.88	5.9%
30,000	$ 4,518.40	$ 4,784.77	$ 266.36	5.9%
35,000	$ 5,268.06	$ 5,578.90	$ 310.84	5.9%
40,000	$ 6,017.71	$ 6,373.03	$ 355.32	5.9%
55,000	$ 8,266.67	$ 8,755.43	$ 488.76	5.9%
75,000	$ 11,265.29	$ 11,931.97	$ 666.68	5.9%
190,000	$ 28,507.35	$ 30,197.05	$ 1,689.70	5.9%
205,000	$ 30,756.31	$ 32,579.45	$ 1,823.14	5.9%

Appendix N Sheet 7 of 23

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Bill Impacts

S.C. No. 2 - Non Demand

Rate Year 1

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	350	370	400	420	440	460	480	510	530
Present Bill	$ 69.79	$ 71.73	$ 74.64	$ 76.59	$ 78.53	$ 80.47	$ 82.41	$ 85.32	$ 87.26
Without Rate Moderation									
Proposed Bill	$ 71.04	$ 73.22	$ 76.50	$ 78.69	$ 80.88	$ 83.07	$ 85.25	$ 88.53	$ 90.72
$ Delivery Rate Increase	$ 1.24	$ 1.49	$ 1.86	$ 2.11	$ 2.35	$ 2.60	$ 2.85	$ 3.21	$ 3.46
% Increase	1.78%	2.08%	2.49%	2.75%	3.00%	3.23%	3.45%	3.77%	3.97%

With Rate Moderation									
EBC Reduction	$ (0.84)	$ (0.89)	$ (0.96)	$ (1.01)	$ (1.05)	$ (1.10)	$ (1.15)	$ (1.22)	$ (1.27)
Proposed Bill	$ 70.20	$ 72.34	$ 75.55	$ 77.68	$ 79.82	$ 81.96	$ 84.10	$ 87.31	$ 89.45
$ Delivery Rate Increase	$ 0.40	$ 0.60	$ 0.90	$ 1.10	$ 1.30	$ 1.50	$ 1.70	$ 1.99	$ 2.19
% Increase	0.58%	0.83%	1.19%	1.42%	1.63%	1.83%	2.02%	2.28%	2.45%

Rate Year 2

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	350	370	400	420	440	460	480	510	530
Present Bill	$ 70.20	$ 72.34	$ 75.55	$ 77.68	$ 79.82	$ 81.96	$ 84.10	$ 87.31	$ 89.45
Without Rate Moderation									
Proposed Bill	$ 73.41	$ 75.79	$ 79.36	$ 81.74	$ 84.12	$ 86.51	$ 88.89	$ 92.46	$ 94.84
$ Delivery Rate Increase	$ 3.21	$ 3.45	$ 3.82	$ 4.06	$ 4.30	$ 4.54	$ 4.78	$ 5.15	$ 5.39
% Increase	4.37%	4.56%	4.81%	4.96%	5.11%	5.25%	5.38%	5.57%	5.68%

With Rate Moderation									
EBC Reduction	$ (1.44)	$ (1.52)	$ (1.65)	$ (1.73)	$ (1.81)	$ (1.89)	$ (1.98)	$ (2.10)	$ (2.18)
Proposed Bill	$ 71.97	$ 74.27	$ 77.72	$ 80.01	$ 82.31	$ 84.61	$ 86.91	$ 90.36	$ 92.66
$ Delivery Rate Increase	$ 1.77	$ 1.93	$ 2.17	$ 2.33	$ 2.49	$ 2.65	$ 2.81	$ 3.05	$ 3.21
% Increase	2.46%	2.60%	2.79%	2.91%	3.02%	3.13%	3.23%	3.37%	3.46%

Rate Year 3

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	350	370	400	420	440	460	480	510	530
Present Bill	$ 71.97	$ 74.27	$ 77.72	$ 80.01	$ 82.31	$ 84.61	$ 86.91	$ 90.36	$ 92.66
Without Rate Moderation									
Proposed Bill	$ 76.81	$ 79.41	$ 83.32	$ 85.92	$ 88.53	$ 91.13	$ 93.74	$ 97.64	$ 100.25
$ Delivery Rate Increase	$ 4.84	$ 5.14	$ 5.60	$ 5.91	$ 6.21	$ 6.52	$ 6.82	$ 7.28	$ 7.59
% Increase	6.30%	6.48%	6.72%	6.88%	7.02%	7.15%	7.28%	7.46%	7.57%

With Rate Moderation									
EBC Reduction	$ (1.78)	$ (1.88)	$ (2.03)	$ (2.13)	$ (2.23)	$ (2.34)	$ (2.44)	$ (2.59)	$ (2.69)
Proposed Bill	$ 75.03	$ 77.53	$ 81.29	$ 83.79	$ 86.29	$ 88.80	$ 91.30	$ 95.05	$ 97.56
$ Delivery Rate Increase	$ 3.06	$ 3.26	$ 3.57	$ 3.77	$ 3.98	$ 4.18	$ 4.39	$ 4.69	$ 4.90
% Increase	4.08%	4.21%	4.39%	4.51%	4.61%	4.71%	4.81%	4.94%	5.02%

Appendix N Sheet 8 of 23

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 1

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 167.96	$ 185.51	$ 203.06	$ 273.26	$ 308.36					
Without Rate Moderation										
Proposed Bill - RY1	$ 177.06	$ 193.99	$ 210.92	$ 278.64	$ 312.51					
$ Delivery Rate Increase	$ 9.10	$ 8.48	$ 7.86	$ 5.38	$ 4.15					
% Increase	5.42%	4.57%	3.87%	1.97%	1.34%					
With Rate Moderation										
EBC Reduction	$ (0.51)	$ (0.77)	$ (1.02)	$ (2.05)	$ (2.56)					
Proposed Bill	$ 176.55	$ 193.23	$ 209.90	$ 276.60	$ 309.95					
Delivery Rate Increase	$ 8.59	$ 7.71	$ 6.84	$ 3.34	$ 1.59					
Total % Increase	5.11%	4.16%	3.37%	1.22%	0.51%					
10										
Present Bill	$ 214.84	$ 232.39	$ 249.94	$ 320.13	$ 355.23					
Without Rate Moderation										
Proposed Bill - RY1	$ 230.18	$ 247.11	$ 264.04	$ 331.76	$ 365.62					
$ Delivery Rate Increase	$ 15.35	$ 14.73	$ 14.11	$ 11.63	$ 10.39					
% Increase	7.14%	6.34%	5.64%	3.63%	2.92%					
With Rate Moderation										
EBC Reduction	$ (0.51)	$ (0.77)	$ (1.02)	$ (2.05)	$ (2.56)					
Proposed Bill	$ 229.67	$ 246.35	$ 263.02	$ 329.72	$ 363.07					
Delivery Rate Increase	$ 14.83	$ 13.96	$ 13.08	$ 9.58	$ 7.83					
% Increase	6.90%	6.01%	5.23%	2.99%	2.20%					
15										
Present Bill			$ 296.81	$ 367.01	$ 402.11	$ 577.60	$ 753.10			
Without Rate Moderation										
Proposed Bill - RY1			$ 317.16	$ 384.88	$ 418.74	$ 588.05	$ 757.35			
$ Delivery Rate Increase			$ 20.35	$ 17.87	$ 16.63	$ 10.44	$ 4.25			
% Increase			6.86%	4.87%	4.14%	1.81%	0.56%			
With Rate Moderation										
EBC Reduction			$ (1.02)	$ (2.05)	$ (2.56)	$ (5.12)	$ (7.68)			
Proposed Bill			$ 316.14	$ 382.84	$ 416.18	$ 582.93	$ 749.67			
Delivery Rate Increase			$ 19.33	$ 15.83	$ 14.08	$ 5.32	$ (3.43)			
% Increase			6.51%	4.31%	3.50%	0.92%	-0.46%			
20										
Present Bill				$ 413.88	$ 448.98	$ 624.48	$ 799.97	$ 975.47		
Without Rate Moderation										
Proposed Bill - RY1				$ 438.00	$ 471.86	$ 641.16	$ 810.47	$ 979.77		
$ Delivery Rate Increase				$ 24.12	$ 22.88	$ 16.69	$ 10.49	$ 4.30		
% Increase				5.83%	5.10%	2.67%	1.31%	0.44%		
With Rate Moderation										
EBC Reduction				$ (2.05)	$ (2.56)	$ (5.12)	$ (7.68)	$ (10.24)		
Proposed Bill				$ 435.95	$ 469.30	$ 636.05	$ 802.79	$ 969.53		
Delivery Rate Increase				$ 22.07	$ 20.32	$ 11.57	$ 2.82	$ (5.94)		
% Increase				5.33%	4.53%	1.85%	0.35%	-0.61%		
30										
Present Bill					$ 542.73	$ 718.23	$ 893.72	$ 1,069.22	$ 1,420.21	
Without Rate Moderation										
Proposed Bill - RY1					$ 578.10	$ 747.40	$ 916.70	$ 1,086.01	$ 1,424.61	
$ Delivery Rate Increase					$ 35.37	$ 29.18	$ 22.98	$ 16.79	$ 4.40	
% Increase					6.52%	4.06%	2.57%	1.57%	0.31%	
With Rate Moderation										
EBC Reduction					$ (2.56)	$ (5.12)	$ (7.68)	$ (10.24)	$ (15.36)	
Proposed Bill					$ 575.54	$ 742.28	$ 909.03	$ 1,075.77	$ 1,409.25	
Delivery Rate Increase					$ 32.81	$ 24.06	$ 15.30	$ 6.55	$ (10.95)	
% Increase					6.05%	3.35%	1.71%	0.61%	-0.77%	
50										
Present Bill						$ 905.73	$ 1,081.22	$ 1,256.72	$ 1,607.71	$ 1,958.70
Without Rate Moderation										
Proposed Bill - RY1						$ 959.88	$ 1,129.18	$ 1,298.48	$ 1,637.09	$ 1,975.69
$ Delivery Rate Increase						$ 54.15	$ 47.96	$ 41.77	$ 29.38	$ 16.99
% Increase						5.98%	4.44%	3.32%	1.83%	0.87%
With Rate Moderation										
EBC Reduction						$ (5.12)	$ (7.68)	$ (10.24)	$ (15.36)	$ (20.47)
Proposed Bill						$ 954.76	$ 1,121.50	$ 1,288.25	$ 1,621.73	$ 1,955.21
Delivery Rate Increase						$ 49.03	$ 40.28	$ 31.53	$ 14.02	$ (3.48)
% Increase						5.41%	3.73%	2.51%	0.87%	-0.18%
100										
Present Bill						$ 1,374.47	$ 1,549.97	$ 1,725.46	$ 2,076.45	$ 2,427.44
Without Rate Moderation										
Proposed Bill - RY1						$ 1,491.07	$ 1,660.37	$ 1,829.67	$ 2,168.28	$ 2,506.88
$ Delivery Rate Increase						$ 116.60	$ 110.40	$ 104.21	$ 91.82	$ 79.44
% Increase						8.48%	7.12%	6.04%	4.42%	3.27%
With Rate Moderation										
EBC Reduction						$ (5.12)	$ (7.68)	$ (10.24)	$ (15.36)	$ (20.47)
Proposed Bill						$ 1,485.95	$ 1,652.69	$ 1,819.44	$ 2,152.92	$ 2,486.41
Delivery Rate Increase						$ 111.48	$ 102.73	$ 93.97	$ 76.47	$ 58.96
% Increase						8.11%	6.63%	5.45%	3.68%	2.43%

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 2

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill - RY1	$ 176.55	$ 193.23	$ 209.90	$ 276.60	$ 309.95					
Without Rate Moderation										
Proposed Bill - RY2	$ 185.59	$ 202.38	$ 219.18	$ 286.34	$ 319.93					
$ Delivery Rate Increase	$ 9.04	$ 9.16	$ 9.27	$ 9.75	$ 9.98					
% Increase	5.12%	4.74%	4.42%	3.52%	3.22%					
With Rate Moderation										
EBC Reduction	$ (0.66)	$ (0.98)	$ (1.31)	$ (2.62)	$ (3.28)					
Proposed Bill	$ 184.94	$ 201.40	$ 217.86	$ 283.72	$ 316.65					
Delivery Rate Increase	$ 8.38	$ 8.17	$ 7.96	$ 7.12	$ 6.71					
Total % Increase	4.75%	4.23%	3.79%	2.58%	2.16%					
10										
Present Bill - RY1	$ 229.67	$ 246.35	$ 263.02	$ 329.72	$ 363.07					
Without Rate Moderation										
Proposed Bill - RY2	$ 242.91	$ 259.70	$ 276.49	$ 343.66	$ 377.24					
$ Delivery Rate Increase	$ 13.24	$ 13.35	$ 13.47	$ 13.94	$ 14.18					
% Increase	5.76%	5.42%	5.12%	4.23%	3.91%					
With Rate Moderation										
EBC Reduction	$ (0.66)	$ (0.98)	$ (1.31)	$ (2.62)	$ (3.28)					
Proposed Bill	$ 242.25	$ 258.72	$ 275.18	$ 341.04	$ 373.97					
Delivery Rate Increase	$ 12.58	$ 12.37	$ 12.16	$ 11.32	$ 10.90					
% Increase	5.48%	5.02%	4.62%	3.43%	3.00%					
15										
Present Bill - RY1			$ 316.14	$ 382.84	$ 416.18	$ 582.93	$ 749.67			
Without Rate Moderation										
Proposed Bill - RY2			$ 333.81	$ 400.98	$ 434.56	$ 602.48	$ 770.40			
$ Delivery Rate Increase			$ 17.67	$ 18.14	$ 18.38	$ 19.55	$ 20.73			
% Increase			5.59%	4.74%	4.42%	3.35%	2.77%			
With Rate Moderation										
EBC Reduction			$ (1.31)	$ (2.62)	$ (3.28)	$ (6.55)	$ (9.83)			
Proposed Bill			$ 332.50	$ 398.35	$ 431.28	$ 595.93	$ 760.57			
Delivery Rate Increase			$ 16.36	$ 15.52	$ 15.10	$ 13.00	$ 10.90			
% Increase			5.17%	4.05%	3.63%	2.23%	1.45%			
20										
Present Bill - RY1				$ 435.95	$ 469.30	$ 636.05	$ 802.79	$ 969.53		
Without Rate Moderation										
Proposed Bill - RY2				$ 458.29	$ 491.88	$ 659.80	$ 827.71	$ 995.63		
$ Delivery Rate Increase				$ 22.34	$ 22.57	$ 23.75	$ 24.93	$ 26.10		
% Increase				5.12%	4.81%	3.73%	3.11%	2.69%		
With Rate Moderation										
EBC Reduction				$ (2.62)	$ (3.28)	$ (6.55)	$ (9.83)	$ (13.10)		
Proposed Bill				$ 455.67	$ 488.60	$ 653.24	$ 817.89	$ 982.53		
Delivery Rate Increase				$ 19.72	$ 19.30	$ 17.20	$ 15.10	$ 13.00		
% Increase				4.52%	4.11%	2.70%	1.88%	1.34%		
30										
Present Bill - RY1					$ 575.54	$ 742.28	$ 909.03	$ 1,075.77	$ 1,409.25	
Without Rate Moderation										
Proposed Bill - RY2					$ 606.51	$ 774.43	$ 942.35	$ 1,110.27	$ 1,446.11	
$ Delivery Rate Increase					$ 30.97	$ 32.14	$ 33.32	$ 34.50	$ 36.85	
% Increase					5.38%	4.33%	3.67%	3.21%	2.62%	
With Rate Moderation										
EBC Reduction					$ (3.28)	$ (6.55)	$ (9.83)	$ (13.10)	$ (19.65)	
Proposed Bill					$ 603.23	$ 767.88	$ 932.52	$ 1,097.16	$ 1,426.45	
Delivery Rate Increase					$ 27.69	$ 25.59	$ 23.49	$ 21.40	$ 17.20	
% Increase					4.81%	3.45%	2.58%	1.99%	1.22%	
50										
Present Bill - RY1						$ 954.76	$ 1,121.50	$ 1,288.25	$ 1,621.73	$ 1,955.21
Without Rate Moderation										
Proposed Bill - RY2						$ 1,003.69	$ 1,171.61	$ 1,339.53	$ 1,675.37	$ 2,011.21
$ Delivery Rate Increase						$ 48.93	$ 50.11	$ 51.29	$ 53.64	$ 56.00
% Increase						5.13%	4.47%	3.98%	3.31%	2.86%
With Rate Moderation										
EBC Reduction						$ (6.55)	$ (9.83)	$ (13.10)	$ (19.65)	$ (26.21)
Proposed Bill						$ 997.14	$ 1,161.79	$ 1,326.43	$ 1,655.72	$ 1,985.00
Delivery Rate Increase						$ 42.38	$ 40.28	$ 38.18	$ 33.99	$ 29.79
% Increase						4.44%	3.59%	2.96%	2.10%	1.52%
100										
Present Bill - RY1						$ 1,485.95	$ 1,652.69	$ 1,819.44	$ 2,152.92	$ 2,486.41
Without Rate Moderation										
Proposed Bill - RY2						$ 1,576.86	$ 1,744.78	$ 1,912.69	$ 2,248.53	$ 2,584.37
$ Delivery Rate Increase						$ 90.90	$ 92.08	$ 93.26	$ 95.61	$ 97.97
% Increase						6.12%	5.57%	5.13%	4.44%	3.94%
With Rate Moderation										
EBC Reduction						$ (6.55)	$ (9.83)	$ (13.10)	$ (19.65)	$ (26.21)
Proposed Bill						$ 1,570.30	$ 1,734.95	$ 1,899.59	$ 2,228.88	$ 2,558.17
Delivery Rate Increase						$ 84.35	$ 82.25	$ 80.15	$ 75.96	$ 71.76
% Increase						5.68%	4.98%	4.41%	3.53%	2.89%

Appendix N Sheet 10 of 23

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 3

kW	kWh 500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill - RY2	$ 184.94	$ 201.40	$ 217.86	$ 283.72	$ 316.65					
Without Rate Moderation										
Proposed Bill - RY3	$ 195.49	$ 212.16	$ 228.83	$ 295.52	$ 328.86					
$ Delivery Rate Increase	$ 10.55	$ 10.76	$ 10.96	$ 11.79	$ 12.21					
% Increase	5.70%	5.34%	5.03%	4.16%	3.86%					
With Rate Moderation										
EBC Reduction	$ (0.80)	$ (1.21)	$ (1.61)	$ (3.21)	$ (4.02)					
Proposed Bill	$ 194.68	$ 210.95	$ 227.22	$ 292.30	$ 324.84					
Delivery Rate Increase	$ 9.75	$ 9.55	$ 9.36	$ 8.58	$ 8.19					
Total % Increase	5.27%	4.74%	4.29%	3.02%	2.59%					
10										
Present Bill - RY2	$ 242.25	$ 258.72	$ 275.18	$ 341.04	$ 373.97					
Without Rate Moderation										
Proposed Bill - RY3	$ 258.33	$ 275.00	$ 291.67	$ 358.36	$ 391.70					
$ Delivery Rate Increase	$ 16.08	$ 16.28	$ 16.49	$ 17.32	$ 17.74					
% Increase	6.64%	6.29%	5.99%	5.08%	4.74%					
With Rate Moderation										
EBC Reduction	$ (0.80)	$ (1.21)	$ (1.61)	$ (3.21)	$ (4.02)					
Proposed Bill	$ 257.53	$ 273.80	$ 290.07	$ 355.15	$ 387.68					
Delivery Rate Increase	$ 15.27	$ 15.08	$ 14.88	$ 14.11	$ 13.72					
% Increase	6.30%	5.83%	5.41%	4.14%	3.67%					
15										
Present Bill - RY2			$ 332.50	$ 398.35	$ 431.28	$ 595.93	$ 760.57			
Without Rate Moderation										
Proposed Bill - RY3			$ 354.52	$ 421.20	$ 454.55	$ 621.26	$ 787.98			
$ Delivery Rate Increase			$ 22.02	$ 22.85	$ 23.26	$ 25.34	$ 27.41			
% Increase			6.62%	5.74%	5.39%	4.25%	3.60%			
With Rate Moderation										
EBC Reduction			$ (1.61)	$ (3.21)	$ (4.02)	$ (8.04)	$ (12.05)			
Proposed Bill			$ 352.91	$ 417.99	$ 450.53	$ 613.23	$ 775.93			
Delivery Rate Increase			$ 20.41	$ 19.63	$ 19.25	$ 17.30	$ 15.36			
% Increase			6.14%	4.93%	4.46%	2.90%	2.02%			
20										
Present Bill - RY2				$ 455.67	$ 488.60	$ 653.24	$ 817.89	$ 982.53		
Without Rate Moderation										
Proposed Bill - RY3				$ 484.05	$ 517.39	$ 684.11	$ 850.82	$ 1,017.54		
$ Delivery Rate Increase				$ 28.38	$ 28.79	$ 30.86	$ 32.94	$ 35.01		
% Increase				6.23%	5.89%	4.72%	4.03%	3.56%		
With Rate Moderation										
EBC Reduction				$ (3.21)	$ (4.02)	$ (8.04)	$ (12.05)	$ (16.07)		
Proposed Bill				$ 480.83	$ 513.37	$ 676.07	$ 838.77	$ 1,001.47		
Delivery Rate Increase				$ 25.16	$ 24.77	$ 22.83	$ 20.88	$ 18.94		
% Increase				5.52%	5.07%	3.49%	2.55%	1.93%		
30										
Present Bill - RY2					$ 603.23	$ 767.88	$ 932.52	$ 1,097.16	$ 1,426.45	
Without Rate Moderation										
Proposed Bill - RY3					$ 643.08	$ 809.80	$ 976.51	$ 1,143.23	$ 1,476.66	
$ Delivery Rate Increase					$ 39.85	$ 41.92	$ 43.99	$ 46.07	$ 50.21	
% Increase					6.61%	5.46%	4.72%	4.20%	3.52%	
With Rate Moderation										
EBC Reduction					$ (4.02)	$ (8.04)	$ (12.05)	$ (16.07)	$ (24.11)	
Proposed Bill					$ 639.06	$ 801.76	$ 964.46	$ 1,127.16	$ 1,452.56	
Delivery Rate Increase					$ 35.83	$ 33.88	$ 31.94	$ 29.99	$ 26.10	
% Increase					5.94%	4.41%	3.43%	2.73%	1.83%	
50										
Present Bill - RY2						$ 997.14	$ 1,161.79	$ 1,326.43	$ 1,655.72	$ 1,985.00
Without Rate Moderation										
Proposed Bill - RY3						$ 1,061.17	$ 1,227.89	$ 1,394.61	$ 1,728.04	$ 2,061.47
$ Delivery Rate Increase						$ 64.03	$ 66.10	$ 68.18	$ 72.32	$ 76.47
% Increase						6.42%	5.69%	5.14%	4.37%	3.85%
With Rate Moderation										
EBC Reduction						$ (8.04)	$ (12.05)	$ (16.07)	$ (24.11)	$ (32.14)
Proposed Bill						$ 1,053.14	$ 1,215.84	$ 1,378.53	$ 1,703.93	$ 2,029.33
Delivery Rate Increase						$ 56.00	$ 54.05	$ 52.11	$ 48.22	$ 44.33
% Increase						5.62%	4.65%	3.93%	2.91%	2.23%
100										
Present Bill - RY2						$ 1,570.30	$ 1,734.95	$ 1,899.59	$ 2,228.88	$ 2,558.17
Without Rate Moderation										
Proposed Bill - RY3						$ 1,689.61	$ 1,856.33	$ 2,023.05	$ 2,356.48	$ 2,689.92
$ Delivery Rate Increase						$ 119.31	$ 121.38	$ 123.46	$ 127.60	$ 131.75
% Increase						7.60%	7.00%	6.50%	5.72%	5.15%
With Rate Moderation										
EBC Reduction						$ (8.04)	$ (12.05)	$ (16.07)	$ (24.11)	$ (32.14)
Proposed Bill						$ 1,681.58	$ 1,844.28	$ 2,006.98	$ 2,332.37	$ 2,657.77
Delivery Rate Increase						$ 111.27	$ 109.33	$ 107.38	$ 103.49	$ 99.60
% Increase						7.09%	6.30%	5.65%	4.64%	3.89%

Appendix N Sheet 11 of 23

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Bill Impacts

S.C. No. 2 - Primary Demand

Rate Year 1

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill	$ 386.87	$ 401.91	$ 416.94	$ 477.09	$ 507.16					
Without Rate Moderation										
Proposed Bill - RY1	$ 422.63	$ 437.14	$ 451.66	$ 509.71	$ 538.74					
$ Delivery Rate Increase	$ 35.76	$ 35.24	$ 34.71	$ 32.62	$ 31.58					
% Increase	9.24%	8.77%	8.33%	6.84%	6.23%					
With Rate Moderation										
EBC Reduction	$ (0.22)	$ (0.33)	$ (0.44)	$ (0.88)	$ (1.10)					
Proposed Bill	$ 422.41	$ 436.81	$ 451.22	$ 508.83	$ 537.64					
Delivery Rate Increase	$ 35.54	$ 34.91	$ 34.27	$ 31.74	$ 30.48					
Total % Increase	9.19%	8.68%	8.22%	6.65%	6.01%					
10										
Present Bill	$ 426.33	$ 441.36	$ 456.40	$ 516.55	$ 546.62					
Without Rate Moderation										
Proposed Bill - RY1	$ 467.15	$ 481.67	$ 496.18	$ 554.24	$ 583.27					
$ Delivery Rate Increase	$ 40.82	$ 40.30	$ 39.78	$ 37.69	$ 36.65					
% Increase	9.58%	9.13%	8.72%	7.30%	6.70%					
With Rate Moderation										
EBC Reduction	$ (0.22)	$ (0.33)	$ (0.44)	$ (0.88)	$ (1.10)					
Proposed Bill	$ 466.93	$ 481.34	$ 495.74	$ 553.36	$ 582.17					
Delivery Rate Increase	$ 40.60	$ 39.97	$ 39.34	$ 36.81	$ 35.55					
Total % Increase	9.52%	9.06%	8.62%	7.13%	6.50%					
15										
Present Bill			$ 495.86	$ 556.00	$ 586.07	$ 736.44	$ 886.80			
Without Rate Moderation										
Proposed Bill - RY1			$ 540.70	$ 598.76	$ 627.79	$ 772.93	$ 918.07			
$ Delivery Rate Increase			$ 44.85	$ 42.76	$ 41.72	$ 36.49	$ 31.27			
% Increase			9.04%	7.69%	7.12%	4.96%	3.53%			
With Rate Moderation										
EBC Reduction			$ (0.44)	$ (0.88)	$ (1.10)	$ (2.20)	$ (3.30)			
Proposed Bill			$ 540.26	$ 597.88	$ 626.69	$ 770.73	$ 914.77			
Delivery Rate Increase			$ 44.41	$ 41.88	$ 40.61	$ 34.29	$ 27.97			
Total % Increase			8.96%	7.53%	6.93%	4.66%	3.15%			
20										
Present Bill				$ 595.46	$ 625.53	$ 775.89	$ 926.26	$ 1,076.62		
Without Rate Moderation										
Proposed Bill - RY1				$ 643.28	$ 672.31	$ 817.45	$ 962.60	$ 1,107.74		
$ Delivery Rate Increase				$ 47.83	$ 46.78	$ 41.56	$ 36.34	$ 31.12		
% Increase				8.03%	7.48%	5.36%	3.92%	2.89%		
With Rate Moderation										
EBC Reduction				$ (0.88)	$ (1.10)	$ (2.20)	$ (3.30)	$ (4.40)		
Proposed Bill				$ 642.40	$ 671.21	$ 815.25	$ 959.29	$ 1,103.34		
Delivery Rate Increase				$ 46.95	$ 45.68	$ 39.36	$ 33.04	$ 26.72		
Total % Increase				7.88%	7.30%	5.07%	3.57%	2.48%		
30										
Present Bill					$ 704.44	$ 854.80	$ 1,005.17	$ 1,155.53	$ 1,456.26	
Without Rate Moderation										
Proposed Bill - RY1					$ 761.36	$ 906.50	$ 1,051.64	$ 1,196.78	$ 1,487.07	
$ Delivery Rate Increase					$ 56.92	$ 51.70	$ 46.48	$ 41.25	$ 30.81	
% Increase					8.08%	6.05%	4.62%	3.57%	2.12%	
With Rate Moderation										
EBC Reduction					$ (1.10)	$ (2.20)	$ (3.30)	$ (4.40)	$ (6.60)	
Proposed Bill					$ 760.26	$ 904.30	$ 1,048.34	$ 1,192.38	$ 1,480.47	
Delivery Rate Increase					$ 55.82	$ 49.50	$ 43.17	$ 36.85	$ 24.21	
Total % Increase					7.92%	5.79%	4.30%	3.19%	1.66%	
50										
Present Bill						$ 1,012.63	$ 1,162.99	$ 1,313.35	$ 1,614.08	$ 1,914.80
Without Rate Moderation										
Proposed Bill - RY1						$ 1,084.59	$ 1,229.74	$ 1,374.88	$ 1,665.16	$ 1,955.44
$ Delivery Rate Increase						$ 71.97	$ 66.74	$ 61.52	$ 51.08	$ 40.64
% Increase						7.11%	5.74%	4.68%	3.16%	2.12%
With Rate Moderation										
EBC Reduction						$ (2.20)	$ (3.30)	$ (4.40)	$ (6.60)	$ (8.80)
Proposed Bill						$ 1,082.39	$ 1,226.43	$ 1,370.48	$ 1,658.56	$ 1,946.64
Delivery Rate Increase						$ 69.76	$ 63.44	$ 57.12	$ 44.48	$ 31.84
Total % Increase						6.89%	5.46%	4.35%	2.76%	1.66%
100										
Present Bill						$ 1,407.19	$ 1,557.55	$ 1,707.91	$ 2,008.64	$ 2,309.36
Without Rate Moderation										
Proposed Bill - RY1						$ 1,529.83	$ 1,674.97	$ 1,820.11	$ 2,110.39	$ 2,400.68
$ Delivery Rate Increase						$ 122.64	$ 117.42	$ 112.20	$ 101.75	$ 91.31
% Increase						8.72%	7.54%	6.57%	5.07%	3.95%
With Rate Moderation										
EBC Reduction						$ (2.20)	$ (3.30)	$ (4.40)	$ (6.60)	$ (8.80)
Proposed Bill						$ 1,527.63	$ 1,671.67	$ 1,815.71	$ 2,103.79	$ 2,391.87
Delivery Rate Increase						$ 120.44	$ 114.12	$ 107.79	$ 95.15	$ 82.51
Total % Increase						8.56%	7.33%	6.31%	4.74%	3.57%

Appendix N Sheet 12 of 23

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Bill Impacts

S.C. No. 2 - Primary Demand

Rate Year 2

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill - RY1	$ 422.41	$ 436.81	$ 451.22	$ 508.83	$ 537.64					
Without Rate Moderation										
Proposed Bill - RY2	$ 460.12	$ 474.60	$ 489.07	$ 546.98	$ 575.93					
$ Delivery Rate Increase	$ 37.71	$ 37.78	$ 37.86	$ 38.14	$ 38.29					
% Increase	8.93%	8.65%	8.39%	7.50%	7.12%					
With Rate Moderation										
EBC Reduction	$ (0.29)	$ (0.43)	$ (0.57)	$ (1.15)	$ (1.43)					
Proposed Bill	$ 459.84	$ 474.17	$ 488.50	$ 545.83	$ 574.50					
Delivery Rate Increase	$ 37.43	$ 37.35	$ 37.28	$ 37.00	$ 36.85					
Total % Increase	8.86%	8.55%	8.26%	7.27%	6.85%					
10										
Present Bill - RY1	$ 466.93	$ 481.34	$ 495.74	$ 553.36	$ 582.17					
Without Rate Moderation										
Proposed Bill - RY2	$ 506.39	$ 520.86	$ 535.34	$ 593.24	$ 622.19					
$ Delivery Rate Increase	$ 39.45	$ 39.52	$ 39.60	$ 39.88	$ 40.03					
% Increase	8.45%	8.21%	7.99%	7.21%	6.88%					
With Rate Moderation										
EBC Reduction	$ (0.29)	$ (0.43)	$ (0.57)	$ (1.15)	$ (1.43)					
Proposed Bill	$ 506.10	$ 520.43	$ 534.76	$ 592.09	$ 620.76					
Delivery Rate Increase	$ 39.17	$ 39.09	$ 39.02	$ 38.74	$ 38.59					
Total % Increase	8.39%	8.12%	7.87%	7.00%	6.63%					
15										
Present Bill - RY1			$ 540.26	$ 597.88	$ 626.69	$ 770.73	$ 914.77			
Without Rate Moderation										
Proposed Bill - RY2			$ 581.60	$ 639.50	$ 668.46	$ 813.21	$ 957.97			
$ Delivery Rate Increase			$ 41.34	$ 41.62	$ 41.77	$ 42.48	$ 43.20			
% Increase			7.65%	6.96%	6.66%	5.51%	4.72%			
With Rate Moderation										
EBC Reduction			$ (0.57)	$ (1.15)	$ (1.43)	$ (2.87)	$ (4.30)			
Proposed Bill			$ 581.03	$ 638.36	$ 667.02	$ 810.35	$ 953.67			
Delivery Rate Increase			$ 40.76	$ 40.48	$ 40.33	$ 39.62	$ 38.90			
Total % Increase			7.55%	6.77%	6.44%	5.14%	4.25%			
20										
Present Bill - RY1				$ 642.40	$ 671.21	$ 815.25	$ 959.29	$ 1,103.34		
Without Rate Moderation										
Proposed Bill - RY2				$ 685.77	$ 714.72	$ 859.48	$ 1,004.23	$ 1,148.99		
$ Delivery Rate Increase				$ 43.36	$ 43.51	$ 44.22	$ 44.94	$ 45.66		
% Increase				6.75%	6.48%	5.42%	4.68%	4.14%		
With Rate Moderation										
EBC Reduction				$ (1.15)	$ (1.43)	$ (2.87)	$ (4.30)	$ (5.73)		
Proposed Bill				$ 684.62	$ 713.29	$ 856.61	$ 999.94	$ 1,143.26		
Delivery Rate Increase				$ 42.22	$ 42.07	$ 41.36	$ 40.64	$ 39.92		
Total % Increase				6.57%	6.27%	5.07%	4.24%	3.62%		
30										
Present Bill - RY1					$ 760.26	$ 904.30	$ 1,048.34	$ 1,192.38	$ 1,480.47	
Without Rate Moderation										
Proposed Bill - RY2					$ 807.25	$ 952.00	$ 1,096.76	$ 1,241.52	$ 1,531.04	
$ Delivery Rate Increase					$ 46.99	$ 47.70	$ 48.42	$ 49.14	$ 50.57	
% Increase					6.18%	5.28%	4.62%	4.12%	3.42%	
With Rate Moderation										
EBC Reduction					$ (1.43)	$ (2.87)	$ (4.30)	$ (5.73)	$ (8.60)	
Proposed Bill					$ 805.81	$ 949.14	$ 1,092.46	$ 1,235.79	$ 1,522.44	
Delivery Rate Increase					$ 45.55	$ 44.84	$ 44.12	$ 43.40	$ 41.97	
Total % Increase					5.99%	4.96%	4.21%	3.64%	2.84%	
50										
Present Bill - RY1						$ 1,082.39	$ 1,226.43	$ 1,370.48	$ 1,658.56	$ 1,946.64
Without Rate Moderation										
Proposed Bill - RY2						$ 1,137.06	$ 1,281.82	$ 1,426.57	$ 1,716.09	$ 2,005.61
$ Delivery Rate Increase						$ 54.66	$ 55.38	$ 56.10	$ 57.53	$ 58.96
% Increase						5.05%	4.52%	4.09%	3.47%	3.03%
With Rate Moderation										
EBC Reduction						$ (2.87)	$ (4.30)	$ (5.73)	$ (8.60)	$ (11.47)
Proposed Bill						$ 1,134.19	$ 1,277.52	$ 1,420.84	$ 1,707.49	$ 1,994.14
Delivery Rate Increase						$ 51.80	$ 51.08	$ 50.37	$ 48.93	$ 47.50
Total % Increase						4.79%	4.17%	3.68%	2.95%	2.44%
100										
Present Bill - RY1						$ 1,527.63	$ 1,671.67	$ 1,815.71	$ 2,103.79	$ 2,391.87
Without Rate Moderation										
Proposed Bill - RY2						$ 1,599.69	$ 1,744.45	$ 1,889.21	$ 2,178.72	$ 2,468.24
$ Delivery Rate Increase						$ 72.07	$ 72.78	$ 73.50	$ 74.93	$ 76.37
% Increase						4.72%	4.35%	4.05%	3.56%	3.19%
With Rate Moderation										
EBC Reduction						$ (2.87)	$ (4.30)	$ (5.73)	$ (8.60)	$ (11.47)
Proposed Bill						$ 1,596.83	$ 1,740.15	$ 1,883.48	$ 2,170.13	$ 2,456.78
Delivery Rate Increase						$ 69.20	$ 68.48	$ 67.77	$ 66.33	$ 64.90
Total % Increase						4.53%	4.10%	3.73%	3.15%	2.71%

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Bill Impacts

S.C. No. 2 - Primary Demand

Rate Year 3

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill - RY2	$ 459.84	$ 474.17	$ 488.50	$ 545.83	$ 574.50					
Without Rate Moderation										
Proposed Bill - RY3	$ 501.30	$ 515.74	$ 530.18	$ 587.94	$ 616.82					
$ Delivery Rate Increase	$ 41.47	$ 41.58	$ 41.68	$ 42.11	$ 42.33					
% Increase	9.02%	8.77%	8.53%	7.72%	7.37%					
With Rate Moderation										
EBC Reduction	$ (0.35)	$ (0.52)	$ (0.70)	$ (1.39)	$ (1.74)					
Proposed Bill	$ 500.96	$ 515.22	$ 529.49	$ 586.55	$ 615.08					
Delivery Rate Increase	$ 41.12	$ 41.06	$ 40.99	$ 40.72	$ 40.59					
Total % Increase	8.94%	8.66%	8.39%	7.46%	7.07%					
10										
Present Bill - RY2	$ 506.10	$ 520.43	$ 534.76	$ 592.09	$ 620.76					
Without Rate Moderation										
Proposed Bill - RY3	$ 549.92	$ 564.36	$ 578.80	$ 636.56	$ 665.44					
$ Delivery Rate Increase	$ 43.82	$ 43.93	$ 44.04	$ 44.47	$ 44.68					
% Increase	8.66%	8.44%	8.24%	7.51%	7.20%					
With Rate Moderation										
EBC Reduction	$ (0.35)	$ (0.52)	$ (0.70)	$ (1.39)	$ (1.74)					
Proposed Bill	$ 549.57	$ 563.84	$ 578.11	$ 635.17	$ 663.70					
Delivery Rate Increase	$ 43.48	$ 43.41	$ 43.34	$ 43.08	$ 42.94					
Total % Increase	8.59%	8.34%	8.11%	7.28%	6.92%					
15										
Present Bill - RY2			$ 579.97	$ 637.30	$ 665.97	$ 809.29	$ 952.62			
Without Rate Moderation										
Proposed Bill - RY3			$ 626.37	$ 684.13	$ 713.01	$ 857.41	$ 1,001.81			
$ Delivery Rate Increase			$ 46.39	$ 46.82	$ 47.04	$ 48.11	$ 49.19			
% Increase			8.00%	7.35%	7.06%	5.95%	5.16%			
With Rate Moderation										
EBC Reduction			$ (0.70)	$ (1.39)	$ (1.74)	$ (3.48)	$ (5.22)			
Proposed Bill			$ 625.67	$ 682.74	$ 711.27	$ 853.93	$ 996.59			
Delivery Rate Increase			$ 45.70	$ 45.43	$ 45.30	$ 44.63	$ 43.97			
Total % Increase			7.88%	7.13%	6.80%	5.52%	4.62%			
20										
Present Bill - RY2				$ 683.22	$ 711.88	$ 855.21	$ 998.53	$ 1,141.86		
Without Rate Moderation										
Proposed Bill - RY3				$ 732.39	$ 761.27	$ 905.67	$ 1,050.07	$ 1,194.47		
$ Delivery Rate Increase				$ 49.18	$ 49.39	$ 50.47	$ 51.54	$ 52.62		
% Increase				7.20%	6.94%	5.90%	5.16%	4.61%		
With Rate Moderation										
EBC Reduction				$ (1.39)	$ (1.74)	$ (3.48)	$ (5.22)	$ (6.96)		
Proposed Bill				$ 731.00	$ 759.53	$ 902.19	$ 1,044.85	$ 1,187.51		
Delivery Rate Increase				$ 47.79	$ 47.65	$ 46.99	$ 46.32	$ 45.66		
Total % Increase				6.99%	6.69%	5.49%	4.64%	4.00%		
30										
Present Bill - RY2					$ 803.71	$ 947.03	$ 1,090.36	$ 1,233.68	$ 1,520.33	
Without Rate Moderation										
Proposed Bill - RY3					$ 857.81	$ 1,002.21	$ 1,146.61	$ 1,291.01	$ 1,579.81	
$ Delivery Rate Increase					$ 54.10	$ 55.18	$ 56.25	$ 57.33	$ 59.48	
% Increase					6.73%	5.83%	5.16%	4.65%	3.91%	
With Rate Moderation										
EBC Reduction					$ (1.74)	$ (3.48)	$ (5.22)	$ (6.96)	$ (10.44)	
Proposed Bill					$ 856.07	$ 998.73	$ 1,141.39	$ 1,284.05	$ 1,569.36	
Delivery Rate Increase					$ 52.36	$ 51.70	$ 51.03	$ 50.37	$ 49.03	
Total % Increase					6.52%	5.46%	4.68%	4.08%	3.23%	
50										
Present Bill - RY2						$ 1,130.68	$ 1,274.01	$ 1,417.33	$ 1,703.98	$ 1,990.63
Without Rate Moderation										
Proposed Bill - RY3						$ 1,195.28	$ 1,339.67	$ 1,484.07	$ 1,772.87	$ 2,061.67
$ Delivery Rate Increase						$ 64.59	$ 65.67	$ 66.74	$ 68.89	$ 71.04
% Increase						5.71%	5.15%	4.71%	4.04%	3.57%
With Rate Moderation										
EBC Reduction						$ (3.48)	$ (5.22)	$ (6.96)	$ (10.44)	$ (13.92)
Proposed Bill						$ 1,191.79	$ 1,334.45	$ 1,477.11	$ 1,762.43	$ 2,047.75
Delivery Rate Increase						$ 61.11	$ 60.45	$ 59.78	$ 58.45	$ 57.12
Total % Increase						5.41%	4.74%	4.22%	3.43%	2.87%
100										
Present Bill - RY2						$ 1,589.80	$ 1,733.13	$ 1,876.45	$ 2,163.10	$ 2,449.75
Without Rate Moderation										
Proposed Bill - RY3						$ 1,677.94	$ 1,822.34	$ 1,966.74	$ 2,255.54	$ 2,544.34
$ Delivery Rate Increase						$ 88.14	$ 89.21	$ 90.29	$ 92.44	$ 94.59
% Increase						5.54%	5.15%	4.81%	4.27%	3.86%
With Rate Moderation										
EBC Reduction						$ (3.48)	$ (5.22)	$ (6.96)	$ (10.44)	$ (13.92)
Proposed Bill						$ 1,674.46	$ 1,817.12	$ 1,959.78	$ 2,245.10	$ 2,530.42
Delivery Rate Increase						$ 84.66	$ 83.99	$ 83.33	$ 82.00	$ 80.67
Total % Increase						5.33%	4.85%	4.44%	3.79%	3.29%

Central Hudson Gas & Electric Corporation

Rates Utilized in Development of Typical Bills

		SC2ND		SC2SD		SC2PD
Market Price Charge - On Peak	$	0.06346	$	0.06346	$	0.06267
Market Price Charge - Off Peak	$	0.06346	$	0.06346	$	0.06267
Market Price Adjustment - On Peak	$	(0.00459)	$	(0.00459)	$	(0.00927)
Market Price Adjustment - Off Peak	$	(0.00459)	$	(0.00459)	$	(0.00927)
Purchased Power Adjustment	$	-	$	-	$	-
Miscellaneous Charges	$	(0.00367)	$	(0.00422)	$	(0.00422)
Miscellaneous Charges (kW)	$	-	$	0.10000	$	0.07000
System Benefits Charge- Current	$	0.00899	$	0.00899	$	0.00899
System Benefits Charge-Modified RY1	$	0.00698	$	0.00698	$	0.00698
System Benefits Charge-Modified RY2	$	0.00698	$	0.00698	$	0.00698
System Benefits Charge-Modified RY3	$	0.00698	$	0.00698	$	0.00698
MFC Admin Charge- Current	$	0.00230	$	0.00011	$	0.00001
MFC Supply Charge- Current	$	0.00332	$	0.00016	$	0.00001
MFC Transition Adjustment	$	-	$	-	$	-
New York State Assessment	$	-	$	-	$	-
Electric Bill Credit- Current	$	(0.00093)	$	(0.00015)	$	(0.00013)
Weighted Revenue Tax - Commodity		0.314%		0.314%		0.314%
Weighted Revenue Tax - Delivery		2.314%		2.314%		2.314%
MFC Admin Charge - Proposed RY1	$	0.00256	$	0.00011	$	0.00001
MFC Admin Charge - Proposed RY2	$	0.00255	$	0.00011	$	0.00001
MFC Admin Charge - Proposed RY3	$	0.00258	$	0.00012	$	0.00001
MFC Supply Charge - Proposed RY1	$	0.00433	$	0.00019	$	0.00002
MFC Supply Charge - Proposed RY2	$	0.00431	$	0.00019	$	0.00002
MFC Supply Charge - Proposed RY3	$	0.00436	$	0.00019	$	0.00002
Electric Bill Credit - Proposed RY1	$	(0.00234)	$	(0.00100)	$	(0.00043)
Electric Bill Credit - Proposed RY2	$	(0.00402)	$	(0.00128)	$	(0.00056)
Electric Bill Credit - Proposed RY3	$	(0.00496)	$	(0.00157)	$	(0.00068)
Customer Charge - Current	$	35.00	$	84.00	$	310.00
Customer Charge - Proposed RY1	$	32.00	$	88.00	$	341.00
Customer Charge - Proposed RY2	$	31.00	$	92.50	$	376.00
Customer Charge - Proposed RY3	$	30.50	$	97.00	$	414.00
On-Peak Delivery - Current	$	0.02702	$	0.00591	$	0.00168
On-Peak Delivery - Proposed RY1	$	0.03887	$	0.00532	$	0.00151
On-Peak Delivery - Proposed RY2	$	0.04838	$	0.00478	$	0.00136
On-Peak Delivery - Proposed RY3	$	0.05921	$	0.00430	$	0.00122
Off-Peak Delivery - Current	$	0.02702	$	0.00591	$	0.00168
Off-Peak Delivery - Proposed RY1	$	0.03887	$	0.00532	$	0.00151
Off-Peak Delivery - Proposed RY2	$	0.04838	$	0.00478	$	0.00136
Off-Peak Delivery - Proposed RY3	$	0.05921	$	0.00430	$	0.00122
Demand Rate - Current		N/A	$	9.06	$	7.64
Demand Rate - Proposed RY1		N/A	$	10.28	$	8.63
Demand Rate - Proposed RY2		N/A	$	11.10	$	8.97
Demand Rate - Proposed RY3		N/A	$	12.18	$	9.43

*SBC rates have been estimated to reflect the inclusion of Energy Efficiency in base rates. In order to only show the impact of base rate increases, annual bills under proposed rates do not however reflect annual changes ECAM (included at January 3, 2018 first billing batch rates).

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Average Annual Residential Gas Heating Customer Bill Impact
Rate Year 1 (Twelve Months Ended June 30, 2019)

Current rates as of January 3, 2018 (First Billing Batch in January)

	Current Rates	Proposed Rates	Current Rates	Proposed Rates	
Block 1 Ccf	24	24	24	24	
Block 2 Ccf	430	430	430	430	
Block 3 Ccf	456	456	456	456	
Total Annual Ccf	**910**	**910**	**910**	**910**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 26.00	$25.00	$26.00	$25.00	
Gas Delivery Charges $/Ccf					
Next	$0.99040	$1.10500	$0.99040	$1.10500	
Next	$0.45420	$0.50600	$0.45420	$0.50600	
System Benefits Charge*	$0.01752	$0.00395	$0.01752	$0.00395	
MFC Admin Charge	$0.00434	$0.00697	$0.00434	$0.00697	
Transition Adj Charge	$0.00269	$0.00000	$0.00269	$0.00000	
Gas Bill Credit	($0.01278)	($0.03950)	($0.01278)	($0.03950)	
Gas Supply Charges $Ccf					
MFC Supply Charge	$0.01297	$0.01908	$0.01297	$0.01908	
Gas Supply Charge	$0.54537	$0.54537	$0.54537	$0.54537	
Rev Tax Factor					
Weighted Rev Tax - Commodity	0.00560	0.00560	0.00560	0.00560	
Weighted Rev Tax - Delivery	0.02560	0.02560	0.02560	0.02560	
CHG&E Bill			LOW INCOME		
Gas Delivery Charges:					
Basic Service Charge	$320.20	$307.88	$320.20	$307.88	
Next	$437.06	$487.63	$437.06	$487.63	
Next	$212.56	$236.80	$212.56	$236.80	
System Benefits Charge	$16.36	$3.69	$16.36	$3.69	
MFC Admin Charge	$4.05	$6.51	$4.05	$6.51	
Transition Adj Charge	$2.51	$0.00	$2.51	$0.00	
Gas Bill Credit	($11.94)	($36.89)	($11.94)	($36.89)	
Subtotal Delivery	$980.81	$1,005.62	$980.81	$1,005.62	
Gas Supply Charges:					
MFC Supply Charge	$12.11	$17.82	$12.11	$17.82	
Gas Supply Charge	$499.08	$499.08	$499.08	$499.08	
Subtotal Energy Supply	$511.19	$516.90	$511.19	$516.90	
Low Income Bill Discount	$0.00	$0.00	($360.00)	($360.00)	(Tier 1 Discount)
Total Bill	**$1,492.00**	**$1,522.52**	**$1,132.00**	**$1,162.52**	
$ Total Bill Increase w/ Rate Moderation		$30.52		$30.52	
% Total Bill Increase w/ Rate Moderation		2.05%		2.70%	
$ Total Bill Increase w/out Rate Moderation		$67.41		$67.41	
% Total Bill Increase w/out Rate Moderation		4.52%		5.96%	

*SBC rates reflect the inclusion of Energy Efficiency in base rates.

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Monthly Typical Bills- Total Bill
Residential
Rate Year 1 (Twelve Months Ended June 30, 2019)

Monthly Ccf	Bill at Current Rates	Bill at Proposed RY 1 Rates	Over Current Amount	%
3	$ 29.42	$ 28.41	$ (1.01)	-3.4%
10	$ 40.55	$ 40.12	$ (0.44)	-1.1%
20	$ 56.46	$ 56.84	$ 0.39	0.7%
30	$ 72.36	$ 73.57	$ 1.21	1.7%
40	$ 88.26	$ 90.30	$ 2.04	2.3%
50	$ 104.16	$ 107.02	$ 2.86	2.7%
80	$ 135.36	$ 138.76	$ 3.40	2.5%
90	$ 145.76	$ 149.34	$ 3.58	2.5%
100	$ 156.16	$ 159.92	$ 3.76	2.4%
125	$ 182.16	$ 186.37	$ 4.21	2.3%
150	$ 208.16	$ 212.82	$ 4.66	2.2%
175	$ 234.16	$ 239.27	$ 5.11	2.2%
200	$ 260.16	$ 265.72	$ 5.57	2.1%
250	$ 312.16	$ 318.62	$ 6.47	2.1%
300	$ 364.15	$ 371.52	$ 7.37	2.0%
350	$ 416.15	$ 424.42	$ 8.27	2.0%
400	$ 468.15	$ 477.32	$ 9.17	2.0%
500	$ 572.15	$ 583.12	$ 10.97	1.9%
750	$ 832.14	$ 847.61	$ 15.48	1.9%
1,000	$ 1,092.13	$ 1,112.11	$ 19.98	1.8%
1,500	$ 1,612.11	$ 1,641.10	$ 28.99	1.8%
2,000	$ 2,132.09	$ 2,170.10	$ 38.00	1.8%
3,000	$ 3,172.06	$ 3,228.08	$ 56.03	1.8%
5,000	$ 5,251.99	$ 5,344.05	$ 92.07	1.8%
10,000	$ 10,451.81	$ 10,633.98	$ 182.17	1.7%

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Commercial Gas Bills Impacts
Rate Year 1 (Twelve Months Ended June 30, 2019)

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Present Monthly Bill	Without Rate Moderation: Proposed RY 1 Monthly Bill	Without Rate Moderation: Delivery $ Increase	Without Rate Moderation: % Increase	With Rate Moderation: Gas Bill Credit	With Rate Moderation: Proposed RY 1 Monthly Bill	With Rate Moderation: Delivery $ Increase	With Rate Moderation: % Increase
2	$ 40.39	$ 40.38	$ (0.00)	-0.01%	$ (0.03)	$ 40.35	$ (0.04)	-0.09%
10	49.47	49.73	0.25	0.51%	(0.16)	49.56	0.09	0.18%
30	72.19	73.09	0.89	1.24%	(0.48)	72.60	0.41	0.56%
50	94.91	96.45	1.53	1.61%	(0.81)	95.64	0.73	0.76%
100	151.71	154.85	3.13	2.07%	(1.61)	153.23	1.52	1.00%
150	197.29	201.32	4.03	2.04%	(2.42)	198.90	1.61	0.82%
200	242.87	247.79	4.93	2.03%	(3.23)	244.57	1.70	0.70%
250	288.44	294.27	5.82	2.02%	(4.03)	290.24	1.79	0.62%
300	334.02	340.74	6.72	2.01%	(4.84)	335.90	1.88	0.56%
400	425.17	433.69	8.52	2.00%	(6.45)	427.24	2.06	0.49%
500	516.33	526.64	10.31	2.00%	(8.07)	518.57	2.24	0.43%
600	607.48	619.58	12.10	1.99%	(9.68)	609.91	2.43	0.40%
800	789.79	805.48	15.69	1.99%	(12.90)	792.58	2.79	0.35%
1000	972.09	991.37	19.28	1.98%	(16.13)	975.24	3.15	0.32%
1500	1,427.86	1,456.11	28.25	1.98%	(24.20)	1,431.92	4.05	0.28%
2000	1,883.63	1,920.85	37.22	1.98%	(32.26)	1,888.59	4.96	0.26%
3000	2,795.16	2,850.32	55.16	1.97%	(48.39)	2,801.93	6.77	0.24%
5000	4,618.23	4,709.27	91.04	1.97%	(80.65)	4,628.62	10.39	0.22%
7500	6,744.72	6,870.80	126.09	1.87%	(120.98)	6,749.83	5.11	0.08%
10000	8,871.20	9,032.33	161.13	1.82%	(161.30)	8,871.03	(0.17)	0.00%
12000	10,572.39	10,761.56	189.17	1.79%	(193.56)	10,567.99	(4.39)	-0.04%
14000	12,273.57	12,490.78	217.21	1.77%	(225.82)	12,264.96	(8.62)	-0.07%
16000	13,974.76	14,220.00	245.24	1.75%	(258.09)	13,961.92	(12.84)	-0.09%
20000	17,377.13	17,678.45	301.32	1.73%	(322.61)	17,355.85	(21.29)	-0.12%
Average Annual Heating Customer @ 5560 Ccf Per Year								
5560	5,794.86	5,910.67	115.82	2.00%	(89.68)	5,820.99	26.13	0.45%

			Present	Proposed RY 1
Weighted Revenue Tax Factor:		Delivery		0.00560
		Commodity		0.00560
Gas Supply Charge (per Ccf):				$ 0.54537
System Benefits Charge (per Ccf):			$ 0.00510	$ 0.00395
S.C. No. 2, 6 & 13 Base Delivery Rates				
	Block 1	First 2 Ccf	$ 39.00	$ 39.00
	Block 2 per Ccf	Next 98 Ccf	$ 0.5494	$ 0.5836
	Block 3 per Ccf	Next 4900 Ccf	$ 0.3262	$ 0.3464
	Block 4 per Ccf	Additional	$ 0.2656	$ 0.2819
Merchant Function Charge (per Ccf):		MFC Admin	$ 0.00419	$ 0.00764
		MFC Supply	$ 0.01251	$ 0.02091
		Transition Adj.	$ 0.01801	$ -
SC 11 EG Gas Bill Credit (per Ccf):			$ (0.00495)	$ (0.00450)
Rate Moderation Gas Bill Credit (per Ccf):			$ -	$ (0.01154)
Gas Bill Credit (per Ccf):			$ (0.00495)	$ (0.01604)

In order to only show the impact of base rate increases, bills under proposed rates do not reflect changes to GSC (included at January 3, 2018 first billing batch rates). SBC rates reflect the inclusion of Energy Efficiency in base rates.

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Average Annual Residential Gas Heating Customer Bill Impact
Rate Year 2 (Twelve Months Ended June 30, 2020)

	Current RY 1 Rates	Proposed RY 2 Rates	Current RY 1 Rates	Proposed RY 2 Rates	
Block 1 Ccf	24	24	24	24	
Block 2 Ccf	430	430	430	430	
Block 3 Ccf	456	456	456	456	
Total Annual Ccf	**910**	**910**	**910**	**910**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 25.00	$24.50	$25.00	$24.50	
Gas Delivery Charges $/Ccf					
Next	$1.10500	$1.22280	$1.10500	$1.22280	
Next	$0.50600	$0.56210	$0.50600	$0.56210	
System Benefits Charge	$0.00395	$0.00395	$0.00395	$0.00395	
MFC Admin Charge	$0.00697	$0.00687	$0.00697	$0.00687	
Transition Adj Charge	$0.00000	$0.00000	$0.00000	$0.00000	
Gas Bill Credit	($0.03950)	($0.04454)	($0.03950)	($0.04454)	
Gas Supply Charges $Ccf					
MFC Supply Charge	$0.01908	$0.01881	$0.01908	$0.01881	
Gas Supply Charge	$0.54537	$0.54537	$0.54537	$0.54537	
Rev Tax Factor					
Weighted Rev Tax - Commodity	0.00560	0.00560	0.00560	0.00560	
Weighted Rev Tax - Delivery	0.02560	0.02560	0.02560	0.02560	
CHG&E Bill			LOW INCOME		
Gas Delivery Charges:					
Basic Service Charge	$307.88	$301.72	$307.88	$301.72	
Next	$487.63	$539.62	$487.63	$539.62	
Next	$236.80	$263.05	$236.80	$263.05	
System Benefits Charge	$3.69	$3.69	$3.69	$3.69	
MFC Admin Charge	$6.51	$6.42	$6.51	$6.42	
Transition Adj Charge	$0.00	$0.00	$0.00	$0.00	
Gas Bill Credit	($36.89)	($41.60)	($36.89)	($41.60)	
Subtotal Delivery	$1,005.62	$1,072.90	$1,005.62	$1,072.90	
Gas Supply Charges:					
MFC Supply Charge	$17.82	$17.57	$17.82	$17.57	
Gas Supply Charge	$499.08	$499.08	$499.08	$499.08	
Subtotal Energy Supply	$516.90	$516.65	$516.90	$516.65	
Low Income Bill Discount	$0.00	$0.00	($360.00)	($360.00)	(Tier 1 Discount)
Total Bill	**$1,522.52**	**$1,589.55**	**$1,162.52**	**$1,229.55**	
$ Total Bill Increase w/ Rate Moderation		$67.03		$67.03	
% Total Bill Increase w/ Rate Moderation		4.40%		5.77%	
$ Total Bill Increase w/out Rate Moderation		$108.62		$108.62	
% Total Bill Increase w/out Rate Moderation		7.13%		9.34%	

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Monthly Typical Bills- Total Bill
Residential
Rate Year 2 (Twelve Months Ended June 30, 2020)

Monthly Ccf	Bill at Current RY 1 Rates	Bill at Proposed RY 2 Rates	Over Current Amount	Over Current %
3	$ 28.41	$ 28.00	$ (0.41)	-1.4%
10	$ 40.12	$ 40.51	$ 0.40	1.0%
20	$ 56.84	$ 58.40	$ 1.55	2.7%
30	$ 73.57	$ 76.28	$ 2.71	3.7%
40	$ 90.30	$ 94.16	$ 3.86	4.3%
50	$ 107.02	$ 112.04	$ 5.01	4.7%
80	$ 138.76	$ 145.34	$ 6.57	4.7%
90	$ 149.34	$ 156.44	$ 7.09	4.7%
100	$ 159.92	$ 167.54	$ 7.61	4.8%
125	$ 186.37	$ 195.29	$ 8.91	4.8%
150	$ 212.82	$ 223.04	$ 10.21	4.8%
175	$ 239.27	$ 250.79	$ 11.51	4.8%
200	$ 265.72	$ 278.54	$ 12.82	4.8%
250	$ 318.62	$ 334.04	$ 15.42	4.8%
300	$ 371.52	$ 389.54	$ 18.02	4.8%
350	$ 424.42	$ 445.04	$ 20.62	4.9%
400	$ 477.32	$ 500.54	$ 23.22	4.9%
500	$ 583.12	$ 611.54	$ 28.42	4.9%
750	$ 847.61	$ 889.04	$ 41.43	4.9%
1,000	$ 1,112.11	$ 1,166.54	$ 54.43	4.9%
1,500	$ 1,641.10	$ 1,721.55	$ 80.44	4.9%
2,000	$ 2,170.10	$ 2,276.55	$ 106.45	4.9%
3,000	$ 3,228.08	$ 3,386.56	$ 158.48	4.9%
5,000	$ 5,344.05	$ 5,606.57	$ 262.52	4.9%
10,000	$ 10,633.98	$ 11,156.61	$ 522.63	4.9%

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Commercial Gas Bills Impacts
Rate Year 2 (Twelve Months Ended June 30, 2020)

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly		**Without Rate Moderation**			**With Rate Moderation**			
Usage Ccf	Present RY 1 Monthly Bill	Proposed RY 2 Monthly Bill	Delivery $ Increase	% Increase	Gas Bill Credit	Proposed RY 2 Monthly Bill	Delivery $ Increase	% Increase
2	$ 40.35	$ 40.38	$ 0.03	0.08%	$ (0.04)	$ 40.34	$ (0.01)	-0.01%
10	49.56	50.13	0.56	1.14%	(0.18)	49.95	0.38	0.77%
30	72.60	74.50	1.89	2.61%	(0.55)	73.95	1.34	1.85%
50	95.64	98.86	3.22	3.37%	(0.92)	97.95	2.31	2.41%
100	153.23	159.78	6.55	4.27%	(1.83)	157.95	4.72	3.08%
150	198.90	207.75	8.85	4.45%	(2.75)	205.00	6.10	3.07%
200	244.57	255.71	11.14	4.56%	(3.66)	252.05	7.48	3.06%
250	290.24	303.68	13.44	4.63%	(4.58)	299.10	8.87	3.05%
300	335.90	351.64	15.74	4.69%	(5.49)	346.15	10.25	3.05%
400	427.24	447.57	20.34	4.76%	(7.32)	440.25	13.02	3.05%
500	518.57	543.51	24.93	4.81%	(9.15)	534.35	15.78	3.04%
600	609.91	639.44	29.53	4.84%	(10.98)	628.46	18.55	3.04%
800	792.58	831.30	38.72	4.89%	(14.64)	816.66	24.08	3.04%
1000	975.24	1,023.16	47.92	4.91%	(18.30)	1,004.86	29.62	3.04%
1500	1,431.92	1,502.82	70.90	4.95%	(27.45)	1,475.36	43.45	3.03%
2000	1,888.59	1,982.47	93.88	4.97%	(36.60)	1,945.87	57.28	3.03%
3000	2,801.93	2,941.79	139.85	4.99%	(54.91)	2,886.88	84.94	3.03%
5000	4,628.62	4,860.41	231.79	5.01%	(91.51)	4,768.90	140.27	3.03%
7500	6,749.83	7,080.95	331.12	4.91%	(137.27)	6,943.68	193.85	2.87%
10000	8,871.03	9,301.48	430.45	4.85%	(183.02)	9,118.46	247.42	2.79%
12000	10,567.99	11,077.91	509.91	4.83%	(219.63)	10,858.28	290.28	2.75%
14000	12,264.96	12,854.34	589.38	4.81%	(256.23)	12,598.10	333.14	2.72%
16000	13,961.92	14,630.76	668.84	4.79%	(292.84)	14,337.92	376.00	2.69%
20000	17,355.85	18,183.62	827.77	4.77%	(366.05)	17,817.57	461.72	2.66%
		Average Annual Heating Customer @ 5560 Ccf Per Year						
5560	5,820.99	6,099.97	278.98	4.79%	(101.76)	5,998.21	177.22	3.04%

Weighted Revenue Tax Factor:		Delivery	0.00560
		Commodity	0.00560
Gas Supply Charge (per Ccf):			$ 0.54537
		Present RY 1	Proposed RY 2
System Benefits Charge (per Ccf):		$ 0.00395	$ 0.00395
S.C. No. 2, 6 & 13 Base Delivery Rates			
Block 1	First 2 Ccf	$ 39.00	$ 39.00
Block 2 per Ccf	Next 98 Ccf	$ 0.5836	$ 0.6340
Block 3 per Ccf	Next 4900 Ccf	$ 0.3464	$ 0.3764
Block 4 per Ccf	Additional	$ 0.2819	$ 0.3057
Merchant Function Charge (per Ccf):	MFC Admin	$ 0.00764	$ 0.00755
	MFC Supply	$ 0.02091	$ 0.02067
	Transition Adj.	$ -	$ -
SC 11 EG Gas Bill Credit (per Ccf):		$ (0.00450)	$ (0.00446)
Rate Moderation Gas Bill Credit (per Ccf):		$ (0.01154)	$ (0.01374)
Gas Bill Credit (per Ccf):		$ (0.01604)	$ (0.01820)

In order to only show the impact of base rate increases, bills under proposed rates do not reflect changes to GSC (included at January 3, 2018 first billing batch rates).

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Average Annual Residential Gas Heating Customer Bill Impact
Rate Year 3 (Twelve Months Ended June 30, 2021)

	Current RY 2 Rates	Proposed RY 3 Rates	Current RY 2 Rates	Proposed RY 3 Rates	
Block 1 Ccf	24	24	24	24	
Block 2 Ccf	430	430	430	430	
Block 3 Ccf	456	456	456	456	
Total Annual Ccf	**910**	**910**	**910**	**910**	
			LOW INCOME		
CHG&E Rates					
Basic Service Charge	$ 24.50	$24.25	$24.50	$24.25	
Gas Delivery Charges $/Ccf					
Next	$1.22280	$1.35930	$1.22280	$1.35930	
Next	$0.56210	$0.62480	$0.56210	$0.62480	
System Benefits Charge	$0.00395	$0.00395	$0.00395	$0.00395	
MFC Admin Charge	$0.00687	$0.00678	$0.00687	$0.00678	
Transition Adj Charge	$0.00000	$0.00000	$0.00000	$0.00000	
Gas Bill Credit	($0.04454)	($0.04400)	($0.04454)	($0.04400)	
Gas Supply Charges $Ccf					
MFC Supply Charge	$0.01881	$0.01855	$0.01881	$0.01855	
Gas Supply Charge	$0.54537	$0.54537	$0.54537	$0.54537	
Rev Tax Factor					
Weighted Rev Tax - Commodity	0.00560	0.00560	0.00560	0.00560	
Weighted Rev Tax - Delivery	0.02560	0.02560	0.02560	0.02560	
CHG&E Bill			LOW INCOME		
Gas Delivery Charges:					
Basic Service Charge	$301.72	$298.65	$301.72	$298.65	
Next	$539.62	$599.86	$539.62	$599.86	
Next	$263.05	$292.39	$263.05	$292.39	
System Benefits Charge	$3.69	$3.69	$3.69	$3.69	
MFC Admin Charge	$6.42	$6.33	$6.42	$6.33	
Transition Adj Charge	$0.00	$0.00	$0.00	$0.00	
Gas Bill Credit	($41.60)	($41.09)	($41.60)	($41.09)	
Subtotal Delivery	$1,072.90	$1,159.82	$1,072.90	$1,159.82	
Gas Supply Charges:					
MFC Supply Charge	$17.57	$17.32	$17.57	$17.32	
Gas Supply Charge	$499.08	$499.08	$499.08	$499.08	
Subtotal Energy Supply	$516.65	$516.41	$516.65	$516.41	
Low Income Bill Discount	$0.00	$0.00	($360.00)	($360.00)	(Tier 1 Discount)
Total Bill	**$1,589.55**	**$1,676.23**	**$1,229.55**	**$1,316.23**	
$ Total Bill Increase w/ Rate Moderation		$86.68		$86.68	
% Total Bill Increase w/ Rate Moderation		5.45%		7.05%	
$ Total Bill Increase w/out Rate Moderation		$127.77		$127.77	
% Total Bill Increase w/out Rate Moderation		8.04%		10.39%	

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Monthly Typical Bills- Total Bill
Residential
Rate Year 3 (Twelve Months Ended June 30, 2021)

Monthly Ccf	Bill at Current RY 2 Rates	Bill at Proposed RY 3 Rates	Over Current Amount	Over Current %
3	$ 28.00	$ 27.88	$ (0.12)	-0.4%
10	$ 40.51	$ 41.38	$ 0.87	2.1%
20	$ 58.40	$ 60.66	$ 2.27	3.9%
30	$ 76.28	$ 79.95	$ 3.67	4.8%
40	$ 94.16	$ 99.23	$ 5.07	5.4%
50	$ 112.04	$ 118.51	$ 6.48	5.8%
80	$ 145.34	$ 153.75	$ 8.41	5.8%
90	$ 156.44	$ 165.50	$ 9.06	5.8%
100	$ 167.54	$ 177.24	$ 9.70	5.8%
125	$ 195.29	$ 206.61	$ 11.32	5.8%
150	$ 223.04	$ 235.97	$ 12.93	5.8%
175	$ 250.79	$ 265.33	$ 14.55	5.8%
200	$ 278.54	$ 294.70	$ 16.16	5.8%
250	$ 334.04	$ 353.42	$ 19.39	5.8%
300	$ 389.54	$ 412.15	$ 22.61	5.8%
350	$ 445.04	$ 470.88	$ 25.84	5.8%
400	$ 500.54	$ 529.61	$ 29.07	5.8%
500	$ 611.54	$ 647.06	$ 35.52	5.8%
750	$ 889.04	$ 940.70	$ 51.66	5.8%
1,000	$ 1,166.54	$ 1,234.34	$ 67.79	5.8%
1,500	$ 1,721.55	$ 1,821.61	$ 100.06	5.8%
2,000	$ 2,276.55	$ 2,408.89	$ 132.33	5.8%
3,000	$ 3,386.56	$ 3,583.44	$ 196.88	5.8%
5,000	$ 5,606.57	$ 5,932.54	$ 325.96	5.8%
10,000	$ 11,156.61	$ 11,805.28	$ 648.67	5.8%

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Commercial Gas Bills Impacts
Rate Year 3 (Twelve Months Ended June 30, 2021)

P.S.C. No. 12 - Gas
Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Present RY 2 Monthly Bill	Without Rate Moderation: Proposed RY 3 Monthly Bill	Delivery $ Increase	% Increase	With Rate Moderation: Gas Bill Credit	Proposed RY 3 Monthly Bill	Delivery $ Increase	% Increase
2	$ 40.34	$ 40.38	$ 0.04	0.09%	$ (0.04)	$ 40.34	$ (0.00)	0.00%
10	49.95	50.59	0.65	1.29%	(0.18)	50.41	0.47	0.93%
30	73.95	76.12	2.17	2.94%	(0.54)	75.58	1.63	2.20%
50	97.95	101.65	3.70	3.78%	(0.90)	100.74	2.79	2.85%
100	157.95	165.46	7.51	4.76%	(1.81)	163.65	5.70	3.61%
150	205.00	215.25	10.25	5.00%	(2.71)	212.54	7.54	3.68%
200	252.05	265.04	12.99	5.15%	(3.62)	261.42	9.37	3.72%
250	299.10	314.83	15.73	5.26%	(4.52)	310.31	11.21	3.75%
300	346.15	364.62	18.47	5.34%	(5.43)	359.19	13.04	3.77%
400	440.25	464.20	23.95	5.44%	(7.24)	456.96	16.71	3.80%
500	534.35	563.78	29.42	5.51%	(9.05)	554.73	20.38	3.81%
600	628.46	663.36	34.90	5.55%	(10.85)	652.50	24.05	3.83%
800	816.66	862.51	45.86	5.62%	(14.47)	848.04	31.38	3.84%
1000	1,004.86	1,061.67	56.81	5.65%	(18.09)	1,043.58	38.72	3.85%
1500	1,475.36	1,559.56	84.20	5.71%	(27.14)	1,532.43	57.06	3.87%
2000	1,945.87	2,057.46	111.59	5.73%	(36.18)	2,021.28	75.41	3.88%
3000	2,886.88	3,053.24	166.37	5.76%	(54.27)	2,998.97	112.09	3.88%
5000	4,768.90	5,044.82	275.92	5.79%	(90.46)	4,954.36	185.46	3.89%
7500	6,943.68	7,337.18	393.50	5.67%	(135.68)	7,201.49	257.82	3.71%
10000	9,118.46	9,629.54	511.09	5.60%	(180.91)	9,448.63	330.17	3.62%
12000	10,858.28	11,463.43	605.15	5.57%	(217.10)	11,246.34	388.06	3.57%
14000	12,598.10	13,297.32	699.22	5.55%	(253.28)	13,044.04	445.94	3.54%
16000	14,337.92	15,131.21	793.29	5.53%	(289.46)	14,841.75	503.83	3.51%
20000	17,817.57	18,798.99	981.42	5.51%	(361.83)	18,437.16	619.59	3.48%
		Average Annual Heating Customer @ 5560 Ccf Per Year						
5560	5,998.21	6,327.19	328.99	5.48%	(100.59)	6,226.61	228.40	3.81%

		Present RY 2	Proposed RY 3
Weighted Revenue Tax Factor:	Delivery		0.00560
	Commodity		0.00560
Gas Supply Charge (per Ccf):			$ 0.54537
System Benefits Charge (per Ccf):		$ 0.00395	$ 0.00395
S.C. No. 2, 6 & 13 Base Delivery Rates			
Block 1	First 2 Ccf	$ 39.00	$ 39.00
Block 2 per Ccf	Next 98 Ccf	$ 0.6340	$ 0.6919
Block 3 per Ccf	Next 4900 Ccf	$ 0.3764	$ 0.4129
Block 4 per Ccf	Additional	$ 0.3057	$ 0.3345
Merchant Function Charge (per Ccf):	MFC Admin	$ 0.00755	$ 0.00749
	MFC Supply	$ 0.02067	$ 0.02050
	Transition Adj.	$ -	$ -
SC 11 EG Gas Bill Credit (per Ccf):		$ (0.00446)	$ (0.00442)
Rate Moderation Gas Bill Credit (per Ccf):		$ (0.01374)	$ (0.01357)
Gas Bill Credit (per Ccf):		$ (0.01820)	$ (0.01799)

In order to only show the impact of base rate increases, bills under proposed rates do not reflect changes to GSC (included at January 3, 2018 first billing batch rates).

Appendix O Sheet 1 of 14

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric RDM Targets

		12 Months Ending Jun-19 Rate Year 1	12 Months Ending Jun-20 Rate Year 2	12 Months Ending Jun-21 Rate Year 3
S.C. No. 1				
	Customer Months	3,100,974	3,118,898	3,133,631
	kWh	1,941,012,280	1,913,313,380	1,880,696,732
	Revenue	$ 221,333,140	$ 231,534,010	$ 245,113,200
S.C. No. 2 - Non-Demand				
	Customer Months	356,558	357,161	357,194
	kWh	157,002,337	157,785,047	155,942,758
	Revenue	$ 18,594,270	$ 19,788,060	$ 21,210,040
S.C. No. 2 - Secondary				
	Customer Months	140,446	140,429	140,238
	kWh	1,385,548,178	1,367,162,372	1,348,493,000
	kW	4,364,394	4,306,321	4,247,449
	Revenue	$ 65,227,515	$ 67,939,200	$ 71,761,369
S.C. No. 2 - Primary				
	Customer Months	1,872	1,871	1,869
	kWh	215,254,000	212,236,655	208,836,502
	kW	557,708	549,888	541,081
	Revenue	$ 5,905,466	$ 6,056,614	$ 6,264,735
S.C. No. 3				
	Customer Months	376	376	374
	kWh	271,759,398	268,175,623	264,097,935
	kW	602,460	594,512	585,472
	Revenue	$ 7,326,638	$ 7,528,433	$ 7,793,850
S.C. No. 5				
	Customer Months	48,094	47,545	47,545
	kWh	12,332,706	12,309,525	12,309,525
	Revenue	$ 1,871,453	$ 1,993,632	$ 2,178,242
S.C. No. 6				
	Customer Months	12,000	12,000	12,000
	kWh	19,030,000	19,030,000	19,030,000
	Revenue	$ 1,392,510	$ 1,449,460	$ 1,525,350
S.C. No. 8				
	Customer Months	2,520	2,520	2,520
	kWh	17,260,000	16,240,000	15,560,000
	Revenue	$ 5,250,750	$ 5,467,696	$ 5,852,351
RDM Revenue Target		**$ 326,901,742**	**$ 341,757,105**	**$ 361,699,137**

Note: Revenues are derived from customer charges, base rate energy delivery charges, base rate demand delivery charges and Merchant Function Charges

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric RDM Targets
Rate Year 1 (Twelve Months Ended June 30, 2019

	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	Total
Service Classification No. 1													
Customer Months	257,341	257,838	257,716	257,886	257,515	258,727	258,812	252,416	265,789	258,863	258,845	259,226	3,100,974
MWh	149,008	177,129	177,159	154,636	137,193	161,453	194,086	190,268	175,869	146,732	131,765	145,714	1,941,012
Revenue	$ 17,396,350	$ 19,669,950	$ 19,669,800	$ 17,860,710	$ 16,449,100	$ 18,426,980	$ 21,055,100	$ 20,613,510	$ 19,735,520	$ 17,245,140	$ 16,040,160	$ 17,170,820	$ 221,333,140
Service Classification No. 2													
Nondemand													
Customer Months	29,137	30,177	29,099	30,099	29,003	30,160	29,206	29,827	29,782	30,248	29,312	30,508	356,558
MWh	11,776	13,621	13,045	12,311	11,334	13,559	14,985	15,640	13,857	13,487	11,748	11,638	157,002
Revenue	$ 1,471,260	$ 1,588,960	$ 1,528,110	$ 1,526,520	$ 1,446,740	$ 1,585,580	$ 1,620,320	$ 1,670,160	$ 1,587,100	$ 1,585,120	$ 1,475,570	$ 1,508,830	$ 18,594,270
Primary													
Customer Months	155	155	155	155	155	151	156	153	153	161	160	163	1,872
MWh	18,577	19,407	18,371	17,607	17,002	17,558	18,114	17,657	17,523	17,415	17,170	18,853	215,254
kW	53,079	48,518	48,990	45,733	44,742	46,820	42,126	43,066	42,739	45,830	45,789	50,276	557,708
Revenue	$ 549,645	$ 513,525	$ 513,275	$ 484,135	$ 473,135	$ 489,401	$ 450,760	$ 456,380	$ 454,210	$ 486,730	$ 485,650	$ 528,920	$ 5,905,466
Secondary													
Customer Months	11,703	11,676	11,722	11,687	11,630	11,686	11,607	11,408	11,988	11,759	11,805	11,775	140,446
MWh	127,035	130,547	129,481	109,848	104,046	110,964	118,097	115,871	110,175	107,120	104,243	118,120	1,385,548
kW	423,449	401,684	411,051	366,161	346,821	341,428	337,419	331,060	324,044	340,063	347,478	393,734	4,364,394
Revenue	$ 6,114,409	$ 5,903,810	$ 5,998,470	$ 5,422,091	$ 5,183,580	$ 5,171,788	$ 5,160,790	$ 5,065,260	$ 5,012,010	$ 5,142,540	$ 5,208,290	$ 5,762,340	$ 65,227,515
Service Classification No. 3													
Customer Months	31	32	32	31	31	31	31	30	31	32	32	32	376
MWh	24,545	24,931	23,911	22,321	21,803	22,966	23,503	20,606	21,456	20,710	21,693	23,313	271,759
kW	53,359	50,880	56,261	49,602	51,301	54,037	49,481	43,843	44,240	46,023	50,448	52,985	602,460
Revenue	$ 646,420	$ 620,430	$ 681,150	$ 604,510	$ 622,400	$ 650,620	$ 599,660	$ 535,890	$ 542,850	$ 566,240	$ 615,600	$ 643,910	$ 7,326,638
Service Classification No. 5													
Customer Months	4,025	4,006	4,043	4,044	4,017	4,048	3,934	4,018	3,995	4,005	3,925	4,034	48,094
MWh	802	896	989	1,144	1,233	1,358	1,293	1,078	1,046	924	830	739	12,333
Revenue	$ 153,262	$ 154,382	$ 155,492	$ 157,342	$ 158,412	$ 159,902	$ 159,122	$ 156,552	$ 156,172	$ 154,712	$ 153,592	$ 152,512	$ 1,871,453
Service Classification No. 6													
Customer Months	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	12,000
MWh	2,170	1,650	1,610	1,240	1,250	1,780	1,520	1,990	1,720	1,640	1,140	1,320	19,030
Revenue	$ 149,710	$ 120,000	$ 117,190	$ 96,220	$ 96,310	$ 127,560	$ 111,980	$ 139,730	$ 123,600	$ 119,430	$ 89,930	$ 100,850	$ 1,392,510
Service Classification No. 8													
Customer Months	210	210	210	210	210	210	210	210	210	210	210	210	2,520
MWh	1,160	1,300	1,430	1,660	1,790	1,970	1,740	1,450	1,410	1,240	1,120	990	17,260
Revenue	$ 437,437	$ 437,500	$ 437,559	$ 437,662	$ 437,721	$ 437,802	$ 437,698	$ 437,568	$ 437,550	$ 437,473	$ 437,419	$ 437,361	$ 5,250,750
Total RDM Revenue Target	**$ 26,918,493**	**$ 29,008,556**	**$ 29,101,046**	**$ 26,589,190**	**$ 24,867,398**	**$ 27,049,633**	**$ 29,595,430**	**$ 29,075,050**	**$ 28,049,012**	**$ 25,737,385**	**$ 24,506,211**	**$ 26,305,543**	**$ 326,901,742**

Appendix O Sheet 3 of 14

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric RDM Targets
Rate Year 2 (Twelve Months Ended June 30, 2020)

	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	Total
Service Classification No. 1													
Customer Months	258,829	259,328	259,205	259,376	259,003	260,223	260,309	253,874	267,326	260,358	260,342	260,725	3,118,898
MWh	146,065	174,181	174,426	152,492	135,337	159,443	192,580	188,512	173,520	144,196	129,407	143,153	1,913,313
Revenue	$ 18,090,170	$ 20,585,950	$ 20,605,070	$ 18,669,320	$ 17,145,250	$ 19,300,790	$ 22,232,210	$ 21,743,830	$ 20,687,480	$ 17,955,510	$ 16,647,740	$ 17,870,690	$ 231,534,010
Service Classification No. 2													
Nondemand													
Customer Months	29,186	30,228	29,148	30,150	29,052	30,211	29,255	29,878	29,832	30,300	29,362	30,559	357,161
MWh	11,874	13,689	13,099	12,365	11,362	13,560	14,922	15,621	13,960	13,622	11,903	11,808	157,785
Revenue	$ 1,560,700	$ 1,693,260	$ 1,627,170	$ 1,617,670	$ 1,528,240	$ 1,685,590	$ 1,731,210	$ 1,789,130	$ 1,695,950	$ 1,691,780	$ 1,567,770	$ 1,599,590	$ 19,788,060
Primary													
Customer Months	155	155	155	155	155	151	156	152	153	161	160	163	1,871
MWh	18,334	19,144	18,135	17,364	16,773	17,316	17,855	17,404	17,276	17,149	16,916	18,570	212,237
kW	52,384	47,861	48,361	45,101	44,139	46,175	41,523	42,449	42,137	45,129	45,108	49,521	549,888
Revenue	$ 563,640	$ 526,120	$ 526,510	$ 496,330	$ 485,400	$ 501,746	$ 461,970	$ 467,390	$ 465,640	$ 498,540	$ 497,660	$ 541,590	$ 6,056,614
Secondary													
Customer Months	11,701	11,674	11,722	11,686	11,630	11,684	11,606	11,408	11,986	11,757	11,803	11,772	140,429
MWh	125,353	128,905	127,924	108,462	102,785	109,673	116,753	114,440	108,582	105,429	102,579	116,275	1,367,162
kW	417,844	396,632	406,107	361,542	342,617	337,457	333,580	326,972	319,359	334,696	341,931	387,585	4,306,321
Revenue	$ 6,382,910	$ 6,158,410	$ 6,263,540	$ 5,664,300	$ 5,417,780	$ 5,400,230	$ 5,383,000	$ 5,279,300	$ 5,218,200	$ 5,354,640	$ 5,426,500	$ 6,004,020	$ 67,939,200
Service Classification No. 3													
Customer Months	31	32	32	31	31	31	31	30	31	32	32	32	376
MWh	24,240	24,622	23,610	22,031	21,519	22,680	23,199	20,331	21,167	20,412	21,380	22,984	268,176
kW	52,696	50,248	55,554	48,957	50,634	53,366	48,840	43,257	43,643	45,360	49,721	52,237	594,512
Revenue	$ 664,230	$ 637,760	$ 699,720	$ 621,060	$ 639,360	$ 668,640	$ 616,250	$ 550,760	$ 557,890	$ 581,320	$ 631,680	$ 660,730	$ 7,528,433
Service Classification No. 5													
Customer Months	3,979	3,960	3,997	3,998	3,971	4,002	3,889	3,972	3,950	3,959	3,880	3,988	47,545
MWh	800	894	987	1,141	1,230	1,355	1,291	1,076	1,045	923	829	738	12,310
Revenue	$ 163,436	$ 164,556	$ 165,666	$ 167,516	$ 168,586	$ 170,076	$ 169,316	$ 166,736	$ 166,356	$ 164,906	$ 163,786	$ 162,696	$ 1,993,632
Service Classification No. 6													
Customer Months	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	12,000
MWh	2,170	1,650	1,610	1,240	1,250	1,780	1,520	1,990	1,720	1,640	1,140	1,320	19,030
Revenue	$ 156,580	$ 124,970	$ 122,040	$ 99,700	$ 99,850	$ 132,990	$ 116,500	$ 145,940	$ 128,840	$ 124,360	$ 93,060	$ 104,630	$ 1,449,460
Service Classification No. 8													
Customer Months	210	210	210	210	210	210	210	210	210	210	210	210	2,520
MWh	1,080	1,200	1,330	1,530	1,660	1,820	1,670	1,390	1,350	1,190	1,070	950	16,240
Revenue	$ 455,518	$ 455,572	$ 455,631	$ 455,721	$ 455,779	$ 455,851	$ 455,784	$ 455,658	$ 455,640	$ 455,568	$ 455,514	$ 455,460	$ 5,467,696
Total RDM Revenue Target	**$ 28,037,184**	**$ 30,346,598**	**$ 30,465,347**	**$ 27,791,617**	**$ 25,940,245**	**$ 28,315,913**	**$ 31,166,240**	**$ 30,598,744**	**$ 29,375,996**	**$ 26,826,624**	**$ 25,483,710**	**$ 27,399,406**	**$ 341,757,105**

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric RDM Targets
Rate Year 3 (Twelve Months Ended June 30, 2021)

	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	Total
Service Classification No. 1													
Customer Months	260,053	260,552	260,430	260,602	260,226	261,451	261,539	255,074	268,588	261,587	261,573	261,956	3,133,631
MWh	142,636	170,730	171,228	149,937	133,142	157,082	190,672	186,320	170,664	141,325	126,724	140,235	1,880,697
Revenue	$ 19,026,510	$ 21,785,040	$ 21,831,330	$ 19,751,600	$ 18,101,050	$ 20,467,250	$ 23,755,370	$ 23,203,510	$ 21,935,280	$ 18,928,200	$ 17,499,340	$ 18,828,720	$ 245,113,200
Service Classification No. 2													
Nondemand													
Customer Months	29,188	30,231	29,151	30,153	29,055	30,214	29,258	29,880	29,835	30,302	29,365	30,562	357,194
MWh	11,722	13,523	12,945	12,229	11,232	13,411	14,745	15,445	13,800	13,468	11,768	11,655	155,943
Revenue	$ 1,665,640	$ 1,816,610	$ 1,745,400	$ 1,728,630	$ 1,629,180	$ 1,808,670	$ 1,867,750	$ 1,933,010	$ 1,822,810	$ 1,815,140	$ 1,674,070	$ 1,703,130	$ 21,210,040
Primary													
Customer Months	155	155	154	155	155	151	156	152	153	160	160	163	1,869
MWh	18,047	18,839	17,855	17,091	16,512	17,042	17,566	17,122	17,001	16,860	16,638	18,263	208,837
kW	51,563	47,097	47,614	44,391	43,452	45,446	40,852	41,761	41,465	44,368	44,369	48,703	541,081
Revenue	$ 582,810	$ 543,570	$ 544,170	$ 513,350	$ 502,310	$ 518,970	$ 477,700	$ 483,340	$ 481,620	$ 514,920	$ 514,650	$ 559,690	$ 6,264,735
Secondary													
Customer Months	11,684	11,658	11,707	11,668	11,614	11,669	11,591	11,391	11,971	11,743	11,786	11,756	140,238
MWh	123,590	127,141	126,213	107,018	101,440	108,262	115,264	112,926	107,058	103,890	101,081	114,610	1,348,493
kW	411,965	391,206	400,677	356,726	338,133	333,116	329,327	322,644	314,876	329,811	336,938	382,030	4,247,449
Revenue	$ 6,737,960	$ 6,494,790	$ 6,610,960	$ 5,981,930	$ 5,722,480	$ 5,697,990	$ 5,673,720	$ 5,562,040	$ 5,496,450	$ 5,644,680	$ 5,724,310	$ 6,336,110	$ 71,761,369
Service Classification No. 3													
Customer Months	31	32	31	31	31	31	30	30	31	32	32	32	374
MWh	23,875	24,251	23,253	21,699	21,194	22,351	22,854	20,023	20,842	20,088	21,040	22,625	264,098
kW	51,903	49,493	54,713	48,220	49,867	52,592	48,114	42,603	42,974	44,640	48,931	51,421	585,472
Revenue	$ 687,760	$ 660,570	$ 722,390	$ 643,230	$ 662,110	$ 692,800	$ 636,610	$ 570,750	$ 578,050	$ 601,920	$ 653,780	$ 683,880	$ 7,793,850
Service Classification No. 5													
Customer Months	3,934	3,915	3,952	3,953	3,926	3,957	3,845	3,927	3,905	3,914	3,836	3,943	47,007
MWh	799	893	985	1,139	1,229	1,353	1,291	1,076	1,044	923	829	738	12,299
Revenue	$ 178,813	$ 179,943	$ 181,043	$ 182,883	$ 183,963	$ 185,453	$ 184,703	$ 182,133	$ 181,753	$ 180,303	$ 179,173	$ 178,083	$ 2,178,242
Service Classification No. 6													
Customer Months	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	990	1,010	12,000
MWh	2,170	1,650	1,610	1,240	1,250	1,780	1,520	1,990	1,720	1,640	1,140	1,320	19,030
Revenue	$ 165,420	$ 131,570	$ 128,480	$ 104,530	$ 104,730	$ 140,150	$ 122,550	$ 154,000	$ 135,730	$ 130,910	$ 97,480	$ 109,800	$ 1,525,350
Service Classification No. 8													
Customer Months	210	210	210	210	210	210	210	210	210	210	210	210	2,520
MWh	1,030	1,150	1,270	1,470	1,590	1,750	1,600	1,330	1,290	1,140	1,030	910	15,560
Revenue	$ 487,576	$ 487,630	$ 487,684	$ 487,774	$ 487,828	$ 487,900	$ 487,832	$ 487,711	$ 487,693	$ 487,625	$ 487,576	$ 487,522	$ 5,852,351
Total RDM Revenue Target	**$ 29,532,489**	**$ 32,099,723**	**$ 32,251,457**	**$ 29,393,927**	**$ 27,393,651**	**$ 29,999,183**	**$ 33,206,235**	**$ 32,576,494**	**$ 31,119,386**	**$ 28,303,698**	**$ 26,830,379**	**$ 28,886,935**	**$ 361,699,137**

Appendix O Sheet 5 of 14
Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric SC 8 RDM Example

Example 1 (no transfer/sale of fixtures):

A	B	C	D	E	F	G	H	I	J	K	L	M
Lamp Watts	Lamp Type	Fixture Wattage	Annual kWh	December kWh	Annual Charge Rate A	Annual Charge Rate C	Monthly Charge Rate A	Monthly Charge Rate C	Total MFC per kWh	Inventory Rate A	Inventory Rate C	Forecast Monthly Revenue Target
70	HPS	86	344	151	$ 169.55	$ 25.59	$ 14.13	$ 2.13	$ 0.00030	10	-	$ 141.35
150	HPS	180	720	317	$ 188.44	$ 42.09	$ 15.70	$ 3.51	$ 0.00030	6	-	$ 94.30
400	HPS	496	1,984	873	$ 257.66	$ 97.52	$ 21.47	$ 8.13	$ 0.00030	8	-	$ 172.02
250	MH	300	1,200	528	$ 259.93	$ 63.16	$ 21.66	$ 5.26	$ 0.00030	6	-	$ 130.12
400	MH	464	1,856	817	$ 252.26	$ 91.90	$ 21.02	$ 7.66	$ 0.00030	10	-	$ 210.44
											Target	$ 748.23
											Actual	$ 748.23
											Over/(Under)	**$ 0.00**

Example 2 (transfer/sale of fixtures):

Forecast Inventory

Lamp Watts	Lamp Type	Fixture Wattage	Annual kWh	December kWh	Annual Charge Rate A	Annual Charge Rate C	Monthly Charge Rate A	Monthly Charge Rate C	Total MFC per kWh	Inventory Rate A	Inventory Rate C	Forecast Monthly Revenue Target
70	HPS	86	344	151	$ 169.55	$ 25.59	$ 14.13	$ 2.13	$ 0.00030	10	-	$ 141.35
150	HPS	180	720	317	$ 188.44	$ 42.09	$ 15.70	$ 3.51	$ 0.00030	6	-	$ 94.30
400	HPS	496	1,984	873	$ 257.66	$ 97.52	$ 21.47	$ 8.13	$ 0.00030	8	-	$ 172.02
250	MH	300	1,200	528	$ 259.93	$ 63.16	$ 21.66	$ 5.26	$ 0.00030	6	-	$ 130.12
400	MH	464	1,856	817	$ 252.26	$ 91.90	$ 21.02	$ 7.66	$ 0.00030	10	-	$ 210.44
											Target	**$ 748.23**

Adjustment Due to Sale

Lamp Watts	Lamp Type	Fixture Wattage	Annual kWh	December kWh	Annual Charge Rate A	Annual Charge Rate C	Monthly Charge Rate A	Monthly Charge Rate C	Total MFC per kWh	Inventory Rate A	Inventory Rate C	Adjustment
70	HPS	86	344	151	$ 169.55	$ 25.59	$ 14.13	$ 2.13	$ 0.00030	5	5	$ (60.00)
150	HPS	180	720	317	$ 188.44	$ 42.09	$ 15.70	$ 3.51	$ 0.00030	3	3	$ (36.57)
400	HPS	496	1,984	873	$ 257.66	$ 97.52	$ 21.47	$ 8.13	$ 0.00030	4	4	$ (53.36)
250	MH	300	1,200	528	$ 259.93	$ 63.16	$ 21.66	$ 5.26	$ 0.00030	3	3	$ (49.20)
400	MH	464	1,856	817	$ 252.26	$ 91.90	$ 21.02	$ 7.66	$ 0.00030	5	5	$ (66.80)
											Total Adjustment	$ (265.93)
											Revised Target	**$ 482.30**

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Actual Inventory

Lamp Watts	Lamp Type	Fixture Wattage	Annual kWh	December kWh	Annual Charge Rate A	Annual Charge Rate C	Monthly Charge Rate A	Monthly Charge Rate C	Total MFC per kWh	Inventory Rate A	Inventory Rate C	Actual Revenue
70	HPS	86	344	151	$ 169.55	$ 25.59	$ 14.13	$ 2.13	$ 0.00030	5	5	$ 81.35
150	HPS	180	720	317	$ 188.44	$ 42.09	$ 15.70	$ 3.51	$ 0.00030	3	3	$ 57.73
400	HPS	496	1,984	873	$ 257.66	$ 97.52	$ 21.47	$ 8.13	$ 0.00030	4	4	$ 118.66
250	MH	300	1,200	528	$ 259.93	$ 63.16	$ 21.66	$ 5.26	$ 0.00030	3	3	$ 80.92
400	MH	464	1,856	817	$ 252.26	$ 91.90	$ 21.02	$ 7.66	$ 0.00030	5	5	$ 143.64
											Actual Revenue	$ 482.30
											Over/(Under)	**$ -**

Rates effective July 1, 2017 utilized for illustrative purposes:

A thru **D** P.S.C. No. 15 - Electricity, 19th Revised Leaf No. 217
E P.S.C. No. 15 - Electricity, 8th Revised Leaf No. 222.2
F P.S.C. No. 15 - Electricity, 19th Revised Leaf No. 217
G P.S.C. No. 15 - Electricity, 15th Revised Leaf No. 220
H F / 12
I G / 12
J Sum of Merchant Function Charge Administration and Supply, P.S.C. No. 15 - Electricity, 9th Revised Leaf No. 163.5.2
K Illustrative assumption
L Illustrative assumption
M (K x H) + (L x I) + (E x J)

Appendix O Sheet 6 of 14
Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Electric Geothermal Rate Impact Credit RDM

Example for Illustrative Purposes

	December 2018 Example	Without Adjustment	As Proposed With Adjustment
A	"Actual" SC 1 Revenue	$ 18,000,000	$ 18,000,000
B	Geothermal Rate Impact Credit Provided	$ -	$ 2,112
C	Adjusted "Actual" SC 1 Revenue	$ 18,000,000	$ 17,997,888
D	SC 1 RDM Target	$ 17,500,000	$ 17,500,000
E	Over/(Under) Revenue Collection	$ 500,000	$ 497,888

A Illustrative assumption
B Illustrative assumption: Payments made to 8 customers during the month (8 x $264)
C A - B
D Illustrative assumption
E C - D

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Gas RDM Targets

S.C. Nos. 1 & 12

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Forecast*	$ 65,515,850	$ 70,823,260	$ 77,182,290
Customer Forecast	70,124	70,874	71,625
Rev/Cust Target**	$ 933.84	$ 998.78	$ 1,077.04

S.C. Nos. 2, 6 & 13

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Forecast*	$ 29,702,350	$ 32,165,020	$ 35,023,900
Customer Forecast	11,812	11,961	12,110
Rev/Cust Target**	$ 2,513.06	$ 2,687.49	$ 2,890.32

*Base revenue excluding MFC revenue
**Please refer to sum of monthly values shown on Appendix O Sheet 8-10.

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Rate Year 1 (Twelve Months Ended June 30, 2019) RDM Targets

S.C. Nos. 1 & 12

	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total
Revenue Forecast*	$ 3,203,920	$ 2,746,050	$ 2,724,400	$ 3,809,580	$ 5,871,610	$ 7,387,720	$ 8,652,160	$ 8,901,110	$ 8,027,450	$ 6,560,440	$ 4,631,030	$ 3,000,380	$ 65,515,850
Customer Forecast	69,788	69,840	69,905	69,967	70,034	70,095	70,148	70,215	70,277	70,343	70,404	70,466	70,124
Rev/Cust Target	$ 45.91	$ 39.32	$ 38.97	$ 54.45	$ 83.84	$ 105.40	$ 123.34	$ 126.77	$ 114.23	$ 93.26	$ 65.78	$ 42.58	$ 933.84

S.C. Nos. 2, 6 & 13

	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total
Revenue Forecast*	$ 1,347,140	$ 1,152,810	$ 1,296,100	$ 1,591,860	$ 2,471,020	$ 3,446,740	$ 4,343,940	$ 4,395,140	$ 3,820,800	$ 2,714,330	$ 1,851,940	$ 1,270,530	$ 29,702,350
Customer Forecast	11,734	11,757	11,767	11,780	11,789	11,804	11,824	11,832	11,846	11,855	11,869	11,881	11,812
Rev/Cust Target	$ 114.81	$ 98.05	$ 110.15	$ 135.13	$ 209.60	$ 292.00	$ 367.38	$ 371.46	$ 322.54	$ 228.96	$ 156.03	$ 106.94	$ 2,513.06

*Base revenue excluding MFC revenue

Appendix O Sheet 9 of 14

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Rate Year 2 (Twelve Months Ended June 30, 2020) RDM Targets

S.C. Nos. 1 & 12

	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Total
Revenue Forecast*	$ 3,365,300	$ 2,851,200	$ 2,826,520	$ 4,046,090	$ 6,363,430	$ 8,072,810	$ 9,498,050	$ 9,775,430	$ 8,790,040	$ 7,136,810	$ 4,964,930	$ 3,132,650	$ 70,823,260
Customer Forecast	70,539	70,591	70,656	70,718	70,785	70,845	70,900	70,965	71,028	71,094	71,156	71,216	70,874
Rev/Cust Target	$ 47.71	$ 40.39	$ 40.00	$ 57.21	$ 89.90	$ 113.95	$ 133.96	$ 137.75	$ 123.75	$ 100.39	$ 69.78	$ 43.99	$ 998.78

S.C. Nos. 2, 6 & 13

	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Total
Revenue Forecast*	$ 1,441,830	$ 1,227,850	$ 1,384,860	$ 1,708,740	$ 2,677,340	$ 3,752,220	$ 4,735,360	$ 4,791,500	$ 4,156,420	$ 2,941,330	$ 1,993,020	$ 1,354,550	$ 32,165,020
Customer Forecast	11,884	11,906	11,916	11,929	11,938	11,953	11,972	11,982	11,995	12,005	12,017	12,031	11,961
Rev/Cust Target	$ 121.33	$ 103.13	$ 116.22	$ 143.24	$ 224.27	$ 313.91	$ 395.54	$ 399.89	$ 346.51	$ 245.01	$ 165.85	$ 112.59	$ 2,687.49

*Base revenue excluding MFC revenue

Appendix O Sheet 10 of 14

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Rate Year 3 (Twelve Months Ended June 30, 2021) RDM Targets

S.C. Nos. 1 & 12

	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Revenue Forecast*	$ 3,573,210	$ 2,993,520	$ 2,965,440	$ 4,341,250	$ 6,954,630	$ 8,880,940	$ 10,487,430	$ 10,798,170	$ 9,686,190	$ 7,821,690	$ 5,372,810	$ 3,307,010	$ 77,182,290
Customer Forecast	71,290	71,342	71,407	71,469	71,535	71,595	71,651	71,716	71,779	71,844	71,907	71,967	71,625
Rev/Cust Target	$ 50.12	$ 41.96	$ 41.53	$ 60.74	$ 97.22	$ 124.04	$ 146.37	$ 150.57	$ 134.94	$ 108.87	$ 74.72	$ 45.95	$ 1,077.04

S.C. Nos. 2, 6 & 13

	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Revenue Forecast*	$ 1,552,200	$ 1,314,500	$ 1,487,430	$ 1,843,600	$ 2,913,940	$ 4,104,460	$ 5,191,290	$ 5,254,370	$ 4,549,070	$ 3,206,160	$ 2,156,500	$ 1,450,380	$ 35,023,900
Customer Forecast	12,033	12,055	12,064	12,079	12,087	12,103	12,121	12,131	12,144	12,154	12,166	12,180	12,110
Rev/Cust Target	$ 129.00	$ 109.04	$ 123.29	$ 152.63	$ 241.08	$ 339.13	$ 428.29	$ 433.14	$ 374.59	$ 263.79	$ 177.26	$ 119.08	$ 2,890.32

*Base revenue excluding MFC revenue

Appendix O Sheet 11 of 14

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Gas MFC Targets

MFC-1 (S.C. Nos. 1, 12 & 16)

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Target	$ 1,540,190	$ 1,539,930	$ 1,540,270

MFC-2 (S.C. Nos. 2, 6, 13 & 15)

	Rate Year 1	Rate Year 2	Rate Year 3
Revenue Target	$ 1,942,190	$ 1,942,120	$ 1,942,740

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Rate Year 1 (Twelve Months Ended June 30, 2019) MFC Targets

MFC-1 (S.C. Nos. 1, 12 & 16)

	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total
Revenue Target	$ 39,590	$ 27,510	$ 26,510	$ 56,620	$ 117,460	$ 205,970	$ 273,770	$ 279,290	$ 235,120	$ 163,750	$ 81,070	$ 33,530	$ 1,540,190

MFC-2 (S.C. Nos. 2, 6, 13 & 15)

	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Total
Revenue Target	$ 69,860	$ 54,120	$ 66,440	$ 89,690	$ 159,670	$ 241,630	$ 322,190	$ 322,710	$ 271,160	$ 176,320	$ 106,540	$ 61,860	$ 1,942,190

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Rate Year 2 (Twelve Months Ended June 30, 2020) MFC Targets

MFC-1 (S.C. Nos. 1, 12 & 16)

	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Total
Revenue Target	$ 39,550	$ 27,470	$ 26,490	$ 56,620	$ 117,470	$ 206,020	$ 273,820	$ 279,280	$ 235,080	$ 163,680	$ 81,000	$ 33,450	$ 1,539,930

MFC-2 (S.C. Nos. 2, 6, 13 & 15)

	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Total
Revenue Target	$ 69,890	$ 54,120	$ 66,420	$ 89,590	$ 159,780	$ 241,950	$ 322,340	$ 322,840	$ 270,960	$ 176,170	$ 106,340	$ 61,720	$ 1,942,120

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460
Rate Year 3 (Twelve Months Ended June 30, 2021) MFC Targets

MFC-1 (S.C. Nos. 1, 12 & 16)

	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Revenue Target	$ 39,530	$ 27,460	$ 26,460	$ 56,630	$ 117,540	$ 206,140	$ 273,980	$ 279,390	$ 235,120	$ 163,680	$ 80,950	$ 33,390	$ 1,540,270

MFC-2 (S.C. Nos. 2, 6, 13 & 15)

	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Revenue Target	$ 70,030	$ 54,180	$ 66,450	$ 89,520	$ 159,730	$ 242,130	$ 322,540	$ 323,170	$ 271,010	$ 176,200	$ 106,230	$ 61,550	$ 1,942,740

Appendix P
Central Hudson Gas and Electric Corporation
Cases 17-E-0459 and 17-G-0460
New & Modified Reporting Requirements

Topic	JP Section	Type	Frequency
Capital Expenditures	V.A.6.a.	Variance reporting	Quarterly and annual
Information Technology Capital	V.A.6.b.	Project prioritization and variance reporting	Quarterly and annual
Cloud-based or SaaS IT solutions	V.B.4.d.	Notice of deferral	As needed
Energy storage projects	V.B.4.j.	Implementation plan	Updated annually
		Notice of change in revenue requirement	As needed
		Expenditure reporting	Quarterly
Fortis overhead allocation methodology	V.H.	Notice of change in methodology	As needed
Danskammer bill credit	IX.A.	Notice of termination of credit	As needed
Rate Adjustment Mechanism	XIV.	Compliance filing	Annually
Training Center and Primary Control Center	XV.	Initial report	One time
		Milestone report	As needed
Gas Type 3 leak ranking	XVII.B.2.	Initial report	One time
		Ranking of prior year backlog	Annually
Gas Safety violations over annual cap	XVII.D.	Implementation plan	As needed
Customer Service Quality Performance Mechanism	XVIII.A.	SQPM / Customer Satisfaction report	Annually
Credit/Debit Card payment	XVIII.B.1.	Report on vendor proposals	One time
		Report on associated costs	Quarterly and annual
		Outreach and education plan	One time
Walk in payment fees	XVIII.B.2.	Plan for eliminating fees	One time
Electronic Deferred Payment Agreements ("e-DPA")	XVIII.B.3.	Study on implementing e-DPA program	One time
Non-Pipe Alternative projects	XX.C.	Implementation plan and BCA	Updated annually
		Technical conference	One time
Gas Demand Response program	XX.D.	Report and BCA upon implementation	Annually
Renewable natural gas interconnect guidance document	XX.E.	Updated document included in Gas Transportation Operating Procedures	One time
Residential Methane Detection Program	XX.F.	Implementation Plan	One time
First Responder Training Program	XX.G.	Implementation Plan	One time
Carbon Reduction Program	XXI.D	Implementation Plan	One time
Non Wires Alternative projects	XXIII, Appendix X	Compliance filing for Initial Incentive	One time
		Implementation plan and BCA	Updated annually
		Expenditure and activity detail reporting	Quarterly

Electric Reliability Performance Mechanism

Electric Reliability

Operation of Mechanism

This electric service Reliability Performance Mechanism ("reliability mechanism" or "RPM") structure has been in effect for Central Hudson Gas & Electric Corporation beginning on June 18, 2010 per the Order in Case 09-E-0888. The reliability mechanism targets were continued per the June 26, 2013 Acquisition Order in Case 12-M-0192 and the Negative Revenue Adjustments ("NRAs") were doubled. The performance metrics adopted in this Joint Proposal are described below and will remain in effect until reset by the Commission. The measurement periods for the reliability mechanism metrics will be on a calendar year basis.

The reliability mechanism establishes the following performance metrics:

(a) threshold standards, consisting of system-wide performance targets for frequency and duration of electric service interruption defined as:

1. CAIDI - Customer Average Interruption Duration Index. The average interruption duration time (customers-hours interrupted) for those customers that experience an interruption during the year.

2. SAIFI - System Average Interruption Frequency Index. It is the average number of times that a customer is interrupted per 1, 000 customers served during the year.

The electric service annual metrics for System Average Frequency Index (SAIFI) shall be a 30 basis point (electric, pre-tax) potential negative revenue adjustment for failure to achieve an annual SAIFI target of 1.38 in 2018, 1.34 in 2019 and 1.30 in 2020. The electric service annual metrics for Customer Average Duration Index (CAIDI) shall be a 30 basis point (electric, pre-tax) potential negative revenue adjustment for failure to achieve an annual CAIDI of 2.50.

(b) The Quarterly Meeting process will continue.

All revenue adjustments related to this reliability mechanism will come from shareholder funds and will be deferred and credited for the benefit of ratepayers through the Rate Adjustment Mechanism as described in Appendix G.

Exclusions

The following exclusions will be applicable to operating performance under this reliability mechanism:

(a) Any outages resulting from a major storm, as defined in 16 NYCRR Part 97 (i. e., at least 10% of the customers interrupted within an operating area or customers out of service for at least 24 hours) , except as otherwise noted.

Electric Reliability Performance Mechanism

(b) Any incident resulting from a catastrophic event beyond the control of the Company, including but not limited to plane crash, water main break, or natural disasters (e. g. , hurricanes, floods, earthquakes).

(c) Any incident where problems beyond the Company's control involving generation or the bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as a result of unsatisfactory performance by the Company.

Reporting

The Company will prepare an annual report(s) on its performance under this reliability mechanism. The annual report(s) will be filed by March 31st of each year to the Secretary.

The reports will state the:

(a) Company's annual system-wide performance under the RPM and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;

(b) Company's performance under the other metrics and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and

(c) Basis for requesting and provide adequate support for all exclusions.

Central Hudson Gas & Electric Corporation
Gas Safety Performance Mechanisms and Positive (PRA) / Negative (NRA) Revenue Adjustments

	Target				Basis Point PRA/(NRA)
Leak Management					
Total Year-End Backlog	100 Leaks				(6) bp
Repairable Leak Backlog	10 Leaks				(12) bp
Type 3 Leak Reduction	20 out of top 25				4 bp
Excavation Damages (per 1000 Tickets)					
	2018	2019	2020	2021	
Gas Total Damage	> 2.60	> 2.60	> 2.55	> 2.50	(27) bp
	>2.35 - ≤2.60	>2.35 - ≤2.60	>2.30 - ≤2.55	>2.25 - ≤2.50	(15) bp
	>2.10 - ≤2.35	>2.10 - ≤2.35	>2.05 - ≤2.30	>2.00 - ≤2.25	(5) bp
	>1.85 - ≤2.10	>1.85 - ≤2.10	>1.80 - ≤2.05	>1.75 - ≤2.00	0 bp
	>1.60 - ≤1.85	>1.60 - ≤1.85	>1.55 - ≤1.80	>1.50 - ≤1.75	5 bp
	≤ 1.60	≤ 1.60	≤ 1.55	≤ 1.50	10 bp
Emergency Response					
30 Minute Response	≥ 90%				6 bp
	≥85% - <90%				4 bp
	≥80% - <85%				2 bp
	≥75% - <80%				0 bp
	< 75%				(9) bp
45 Minute Response	<90%				(6) bp
60 Minute Response	<95%				(3) bp
Gas Safety Violations (NYCRR Parts 255 & 261)					
High Risk Violations	Record Violations		Field Violations		
	1-5	0	1-20	(1/2)	
	6-20	(1/2)	21+	(1)	
	21+	(1)			
Other Risk Violations	Record Violations		Field Violations		
	1-15	0	All	(1/4)	
	16+	(1/4)			
	255.603 only cited as single occurrence for failure to follow procedure				
Leak Prone Gas Pipe ("LPP")					
Annual LPP Replacement	15 miles (2018-2021)				(12) bp
LPP Incentive	capped at annual maximum of 6 mi or 12 bp				2 bp / mile

HIGH RISK SECTIONS PART 255

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Material - General	255.53(a),(b),(c)	HIGH
Transportation of Pipe	255.65	HIGH
Pipe Design - General	255.103	HIGH
Design of Components - General Requirements	255.143	HIGH
Design of Components - Flexibility	255.159	HIGH
Design of Components - Supports and anchors	255.161	HIGH
Compressor Stations: Emergency shutdown	255.167	HIGH
Compressor Stations: Pressure limiting devices	255.169	HIGH
Compressor Stations: Ventilation	255.173	HIGH
Valves on pipelines to operate at 125 psig or more	255.179	HIGH
Distribution line valves	255.181	HIGH
Vaults: Structural Design requirements	255.183	HIGH
Vaults: Drainage and waterproofing	255.189	HIGH
Protection against accidental overpressuring	255.195	HIGH
Control of the pressure of gas delivered from high pressure distribution systems	255.197	HIGH
Requirements for design of pressure relief and limiting devices	255.199	HIGH
Required capacity of pressure relieving and limiting stations	255.201	HIGH
Qualification of welding procedures	255.225	HIGH
Qualification of Welders	255.227	HIGH
Protection from weather	255.231	HIGH
Miter Joints	255.233	HIGH
Preparation for welding	255.235	HIGH
Inspection and test of welds	255.241(a),(b)	HIGH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(a)-(e)	HIGH
Welding inspector	255.244(a),(b),(c)	HIGH
Repair or removal of defects	255.245	HIGH
Joining Of Materials Other Than By Welding - General	255.273	HIGH
Joining Of Materials Other Than By Welding - Copper Pipe	255.279	HIGH
Joining Of Materials Other Than By Welding - Plastic Pipe	255.281	HIGH
Plastic pipe: Qualifying persons to make joints	255.285(a),(b),(d)	HIGH
Notification requirements	255.302	HIGH
Compliance with construction standards	255.303	HIGH
Inspection: General	255.305	HIGH
Inspection of materials	255.307	HIGH
Repair of steel pipe	255.309	HIGH
Repair of plastic pipe	255.311	HIGH
Bends and elbows	255.313(a),(b),(c)	HIGH
Wrinkle bends in steel pipe	255.315	HIGH
Installation of plastic pipe	255.321	HIGH
Underground clearance	255.325	HIGH
Customer meters and service regulators: Installation	255.357(d)	HIGH
Service lines: Installation	255.361(e),(f),(g),(h),(i)	HIGH
Service lines: Location of valves	255.365(b)	HIGH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(d),(e)	HIGH
External corrosion control: Buried or submerged pipelines installed before August 1, 1971	255.457	HIGH
External corrosion control: Protective coating	255.461(c)	HIGH
External corrosion control: Cathodic protection	255.463	HIGH
External corrosion control: Monitoring	255.465(a),(e)	HIGH
Internal corrosion control: Design and construction of transmission line	255.476(a),(c)	HIGH
Remedial measures: General	255.483	HIGH
Remedial measures: transmission lines	255.485(a),(b)	HIGH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(a),(b),(c),(d)	HIGH
General requirements (UPGRADES)	255.553 (a),(b),(c),(f)	HIGH
Upgrading to a pressure of 125 PSIG or more in steel pipelines	255.555	HIGH
Upgrading to a pressure less than 125 PSIG	255.557	HIGH
Conversion to service subject to this Part	255.559(a)	HIGH
General provisions	255.603	HIGH
Operator Qualification	255.604	HIGH
Essentials of operating and maintenance plan	255.605	HIGH
Change in class location: Required study	255.609	HIGH
Damage prevention program	255.614	HIGH
Emergency Plans	255.615	HIGH
Customer education and information program	255.616	HIGH
Maximum allowable operating pressure: Steel or plastic pipelines	255.619	HIGH
Maximum allowable operating pressure: High pressure distribution systems	255.621	HIGH
Maximum and minimum allowable operating pressure: Low pressure distribution systems	255.623	HIGH
Odorization of gas	255.625(a),(b)	HIGH

High and Other Gas Risk Safety Violations

Tapping pipelines under pressure	255.627	HIGH
Purging of pipelines	255.629	HIGH
Control Room Management	255.631(a)	HIGH
Transmission lines: Patrolling	255.705	HIGH
Leakage Surveys - Transmission	255.706	HIGH
Transmission lines: General requirements for repair procedures	255.711	HIGH
Transmission lines: Permanent field repair of imperfections and damages	255.713	HIGH
Transmission lines: Permanent field repair of welds	255.715	HIGH
Transmission lines: Permanent field repair of leaks	255.717	HIGH
Transmission lines: Testing of repairs	255.719	HIGH
Distribution systems: Leak surveys and procedures	255.723	HIGH
Compressor stations: procedures	255.729	HIGH
Compressor stations: Inspection and testing relief devices	255.731	HIGH
Compressor stations: Additional inspections	255.732	HIGH
Compressor stations: Gas detection	255.736	HIGH
Pressure limiting and regulating stations: Inspection and testing	255.739(a),(b)	HIGH
Regulator Station Overpressure Protection	255.743(a),(b)	HIGH
Transmission Line Valves	255.745	HIGH
Prevention of accidental ignition	255.751	HIGH
Protecting cast iron pipelines	255.755	HIGH
Replacement of exposed or undermined cast iron piping	255.756	HIGH
Replacement of cast iron mains paralleling excavations	255.757	HIGH
Leaks: Records	255.807(d)	HIGH
Leaks: Instrument sensitivity verification	255.809	HIGH
Leaks: Type 1	255.811(b),(c),(d),(e)	HIGH
Leaks: Type 2A	255.813(b),(c),(d)	HIGH
Leaks: Type 2	255.815	HIGH
Leak Follow-up	255.819(a)	HIGH
High Consequence Areas	255.905	HIGH
Required Elements (IMP)	255.911	HIGH
Knowledge and Training (IMP)	255.915	HIGH
Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	255.917	HIGH
Baseline Assessment Plan(IMP)	255.919	HIGH
Conducting a Baseline Assessment (IMP)	255.921	HIGH
Direct Assessment (IMP)	255.923	HIGH
External Corrosion Direct Assessment (ECDA) (IMP)	255.925	HIGH
Internal Corrosion Direct Assessment (ICDA) (IMP)	255.927	HIGH
Confirmatory Direct Assessment (CDA) (IMP)	255.931	HIGH
Addressing Integrity Issues (IMP)	255.933	HIGH
Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	255.935	HIGH
Continual Process of Evaluation and Assessment (IMP)	255.937	HIGH
Reassessment Intervals (IMP)	255.939	HIGH
General requirements of a GDPIM plan	255.1003	HIGH
Implementation requirements of a GDPIM plan.	255.1005	HIGH
Required elements of a GDPIM plan.	255.1007	HIGH
Required report when compression couplings fail.	255.1009	HIGH
Requirements a small liquefied petroleum gas (LPG) operator must satisfy to implement a GDPIM plan	255.1015	HIGH

HIGH RISK SECTIONS PART 261		
Operation and maintenance plan	261.15	HIGH
Leakage Survey	261.17(a),(c)	HIGH
Carbon monoxide prevention	261.21	HIGH
Warning tag procedures	261.51	HIGH
HEFPA Liaison	261.53	HIGH
Warning Tag Inspection	261.55	HIGH
Warning tag: Class A condition	261.57	HIGH
Warning tag: Class B condition	261.59	HIGH

OTHER RISK SECTIONS PART 255

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Preservation of records	255.17	OTH
Compressor station: Design and construction	255.163	OTH
Compressor station: Liquid removal	255.165	OTH
Compressor stations: Additional safety equipment	255.171	OTH
Vaults: Accessibility	255.185	OTH
Vaults: Sealing, venting, and ventilation	255.187	OTH
Calorimeter or calorimeter structures	255.190	OTH
Design pressure of plastic fittings	255.191	OTH
Valve installtion in plastic pipe	255.193	OTH
Instrument, control, and sampling piping and components	255.203	OTH
Limitations On Welders	255.229	OTH
Quality assurance program	255.230	OTH
Preheating	255.237	OTH
Stress relieving	255.239	OTH
Inspection and test of welds	255.241(c)	OTH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(f)	OTH
Plastic pipe: Qualifying joining procedures	255.283	OTH
Plastic pipe: Qualifying persons to make joints	255.285(c),(e)	OTH
Plastic pipe: Inspection of joints	255.287	OTH
Bends and elbows	255.313(d)	OTH
Protection from hazards	255.317	OTH
Installation of pipe in a ditch	255.319	OTH
Casing	255.323	OTH
Cover	255.327	OTH
Customer meters and regulators: Location	255.353	OTH
Customer meters and regulators: Protection from damage	255.355	OTH
Customer meters and service regulators: Installation	255.357(a),(b),(c)	OTH
Customer meter installations: Operating pressure	255.359	OTH
Service lines: Installation	255.361(a),(b),(c),(d)	OTH
Service lines: valve requirements	255.363	OTH
Service lines: Location of valves	255.365(a),(c)	OTH
Service lines: General requirements for connections to main piping	255.367	OTH
Service lines: Connections to cast iron or ductile iron mains	255.369	OTH
Service lines: Steel	255.371	OTH
Service lines: Cast iron and ductile iron	255.373	OTH
Service lines: Plastic	255.375	OTH
Service lines: Copper	255.377	OTH
New service lines not in use	255.379	OTH
Service lines: excess flow valve performance standards	255.381	OTH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(a)	OTH
External corrosion control: Examination of buried pipeline when exposed	255.459	OTH
External corrosion control: Protective coating	255.461(a),(b),(d),(e),(f),(g)	OTH
Rectifier Inspection	255.465 (b),(c),(f)	OTH
External corrosion control: Electrical isolation	255.467	OTH
External corrosion control: Test stations	255.469	OTH
External corrosion control: Test lead	255.471	OTH
External corrosion control: Interference currents	255.473	OTH
Internal corrosion control: General	255.475(a),(b)	OTH
Atmospheric corrosion control: General	255.479	OTH
Atmospheric corrosion control: Monitoring	255.481	OTH
Remedial measures: transmission lines	255.485(c)	OTH
Remedial measures: Pipelines lines other than cast iron or ductile iron lines	255.487	OTH
Remedial measures: Cast iron and ductile iron pipelines	255.489	OTH
Direct Assessment	255.490	OTH
Corrosion control records	255.491	OTH
General requirements (TESTING)	255.503	OTH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(e),(h),(i)	OTH

Central Hudson Gas and Electric Corporation
Cases 17-E-0459; 17-G-0460
Part 255 / 261
High and Other Gas Risk Safety Violations

Test requirements for pipelines to operate at less than 125 PSIG	255.507	OTH
Test requirements for service lines	255.511	OTH
Environmental protection and safety requirements	255.515	OTH
Records (TESTING)	255.517	OTH
Notification requirements (UPGRADES)	255.552	OTH
General requirements (UPGRADES)	255.553(d),(e)	OTH
Conversion to service subject to this Part	255.559(b)	OTH
Change in class location: Confirmation or revision of maximum allowable operating pressure	255.611(a),(d)	OTH
Continuing surveillance	255.613	OTH
Odorization	255.625(e),(f)	OTH
Pipeline Markers	255.707(a),(c),(d),(e)	OTH
Transmission lines: Record keeping	255.709	OTH
Distribution systems: Patrolling	255.721(b)	OTH
Test requirements for reinstating service lines	255.725	OTH
Inactive Services	255.726	OTH
Abandonment or inactivation of facilities	255.727(b)-(g)	OTH
Compressor stations: storage of combustible materials	255.735	OTH
Pressure limiting and regulating stations: Inspection and testing	255.739(c),(d)	OTH
Pressure limiting and regulating stations: Telemetering or recording gauges	255.741	OTH
Regulator Station MAOP	255.743 (c)	OTH
Service Regulator - Min.& Oper. Load	255.744 (d),(e)	OTH
Distribution Line Valves	255.747	OTH
Valve maintenance: Service line valves	255.748	OTH
Regulator Station Vaults	255.749	OTH
Caulked bell and spigot joints	255.753	OTH
Reports of accidents	255.801	OTH
Emergency lists of operator personnel	255.803	OTH
Leaks General	255.805(a),(b),(e),(g),(h)	OTH
Leaks: Records	255.807(a),(b),(c)	OTH
Type 2	255.815(b),(c),(d)	OTH
Type 3	255.817	OTH
Interruptions of service	255.823(a),(b)	OTH
Logging and analysis of gas emergency reports	255.825	OTH
Annual Report	255.829	OTH
Reporting safety-related conditions	255.831	OTH
General (IMP)	255.907	OTH
Changes to an Integrity Management Program (IMP)	255.909	OTH
Low Stress Reassessment (IMP)	255.941	OTH
Measuring Program Effectiveness (IMP)	255.945	OTH
Records (IMP)	255.947	OTH
Records an operator must keep	255.1011	OTH

OTHER RISK SECTIONS PART 261		
High Pressure Piping - Annual Notice	261.19	OTH
Warning tag: Class C condition	261.61	OTH
Warning tag: Action and follow-up	261.63(a)-(h)	OTH
Warning Tag Records	261.65	OTH

Appendix T
Central Hudson Gas and Electric Corporation
Cases 17-E-0459; 17-G-0460

Central Hudson Gas & Electric Corporation
Customer Service Quality Performance Mechanisms and Positive (PRA) / Negative (NRA) Revenue Adjustments

Target	Incentive/ (Penalty)

Customer Satisfaction Index

Target	Incentive/ (Penalty)
>=87%	None
<87% but >=86%	($300,000)
<86% but >=85%	($600,000)
<85% but >=84%	($900,000)
<84%	($1,200,000)

PSC Complaint Rate

Target	Incentive/ (Penalty)
<1.0	None
>=1.0 but <1.1	($300,000)
>=1.1 but <1.2	($600,000)
>=1.2 but < 1.3	($900,000)
>=1.3	($1,200,000)

Residential Service Terminations / Uncollectibles

	Residential Terminations	Residential Bad Debt
5yr Avg	11,661	$5,115,077
Lower	7,500	$3,400,000

Target	Incentive/ (Penalty)
Both Measures <= Lower Target	$925,000
One Measure <= Lower Target; Other <= 5yr Avg	$462,500

Call Answer Rate Within 30 Seconds

Target	Incentive/ (Penalty)
>=60%	None
<60% but >=58%	($150,000)
<58% but >=56%	($300,000)
<56% but >=54%	($450,000)
<54%	($600,000)

Appointments Kept

$20 per Missed Appointment

Major Storm Reserve Funding

The electric Income Statements set forth in Appendix A incorporate $1,558,000 in funding for a Major Storm Reserve for each Rate Year. To the extent that the Company incurs incremental major storm damage costs in excess of the amount accrued in the Major Storm Reserve over the term of the rate plan, the Company will defer expenses for the future recovery from customers, and the rate allowance for the Major Storm Reserve will be adjusted accordingly during the Company's next rate proceeding. To the extent that the Company incurs major storm damage expenses less than the amount accrued in the Major Storm Reserve over the term of the rate plan, 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, before consideration of the 3% deductible described below, 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.

The Company will exclude as a deductible from costs chargeable to the Major Storm Reserve an amount equal to 3 percent of the incremental costs incurred (net of insurance and other recoveries) as a result of the occurrence of the storm event. The Company will charge the deductible amount to non-major storm expense, as well as all other expenses not charged to the reserve.

The Company is authorized to charge the Major Storm Reserve for costs incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a Major Storm, but which ultimately does not do so, when the costs exceed $500,000. The Company is authorized, not more than twice per rate year, to charge the Major Storm Reserve for costs incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a Major Storm, but which ultimately does not do so, when the costs exceed $250,000. The cost to obtain mutual assistance includes the cost of travel to and from Central Hudson. If the costs associated with securing and obtaining the mutual assistance for a storm that does not ultimately meet the definition of a major storm is less than the $500,000, or $250,000 as described above, threshold, the Company will charge the costs to its non-major storm expense (O&M expense).

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 90 days of the date on which the Company is able to serve all customers. 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 180 days of receipt of storm cost documentation from the Company, in order to satisfy the needs of the Company's external auditors that storm costs are properly charged to the reserve and recoverability of incremental costs is highly probable. Such communication will not limit Staff's further review and will have no binding effect in the next rate case. Final incremental costs and the method of recovery are subject to Commission review and approval in Central Hudson's next rate case.

Consistent with current practice, Staff will continue to allow the inclusion of estimated costs in the Company's storm cost documentation. As such, to the extent that final invoices are not received within the 180 day audit period noted above, the Company will provide Staff final bills upon receipt, and costs charged to the Major Storm Reserve will be adjusted accordingly.

Appendix V, Sheet 1 of 3

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 and 17-G-0460
Depreciation Factors and Rates

	ELECTRIC	Effective as of 7/1/15				Effective as of 7/1/18			
Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate	ASL	Curve Type	Net Salv. %	Annual Rate
HYDRO PRODUCTION									
331-00-1	STRUCTURES & IMPROVEMENTS	75	S0	-45	0.0193	85	R1.5	-40	0.0165
332-00-1	RESERVOIRS, DAMS	85	S1	-45	0.0171	85	S3	-40	0.0165
333-00-1	TURBINES & GENERATORS	70	S1	-55	0.0221	75	R2.5	-55	0.0207
334-10-1	ACCESSORY ELEC. EQUIP.	55	R1.5	-55	0.0282	55	R1.5	-55	0.0282
335-00-1	MISC. POWER PLANT EQUIP.	45	L1.5	-25	0.0278	45	L1.5	-25	0.0278
OTHER PRODUCTION									
341-00-1	STRUCTURES AND IMPROVEMENTS	50	R4	-10	0.0220	50	R4	-10	0.0220
342-00-1	FUEL HOLDERS, PRODUCERS & ACCESSORIES	45	R5	-5	0.0233	45	R5	-5	0.0233
343-00-1	PRIME MOVERS	25	R4	-5	0.0420	25	R5	-10	0.0440
344-00-1	GENERATORS	40	R1	-10	0.0275	40	R1	-10	0.0275
345-00-1	ACCESSORY ELECTRIC EQUIPMENT	38	R2	-15	0.0303	40	R2	-15	0.0288
346-00-1	MISCELLANEOUS POWER PLANT EQUIPMENT	35	R2.5	0	0.0286	35	R2.5	0	0.0286
TRANSMISSION									
350-11&15-1	LAND & LAND RIGHTS	80	R3	0	0.0125	90	R4	0	0.0111
350-13-1	LAND & LAND RIGHTS SUBSTATIONS	80	R3	0	0.0125	80	R3	0	0.0125
352-00-1	STRUCTURES & IMPROVEMENTS	75	R3	-15	0.0153	80	R3	-10	0.0138
353-11	STATION EQUIPMENT	53	R1	-20	0.0226	53	R1	-20	0.0226
353-12-1	SUPERVISORY EQUIPMENT- IN USE	33	L1.5	-20	0.0364	33	L1.5	-20	0.0364
353-20-1	SUPERVISORY EQUIPMENT- HELD	53	R1	-20	0.0226	35	R1	-20	0.0343
353-30-1	STATION EQUIP-ELECTRONIC	30	S2	-20	0.0400	30	S2	-20	0.0400
354-00-1	TOWERS & FIXTURES	75	R1	-25	0.0167	80	R2.5	-30	0.0163
355-00, 10 &15-1	POLES & FIXTURES	55	R2.5	-45	0.0264	55	R2.5	-50	0.0273
356-10-1	OVERHEAD COND. & DEVICES	65	R2	-30	0.0200	70	R1.5	-35	0.0193
356-15-1	OVERHEAD COND. & DEV. 345KV	65	R2	-30	0.0200	65	R2	-35	0.0208
356-20&25-1	OVERHEAD LINES, CLEARING	65	R2	-30	0.0200	65	R2	-35	0.0208
357-00-1	UNDERGROUND CONDUIT	40	R0.5	0	0.0250	40	R0.5	0	0.0250
358-00-1	UNERGROUND COND. & DEVICES	50	R0.5	-5	0.0210	60	R2.5	-5	0.0175
DISTRIBUTION									
360-11&22-1	LAND & LAND RIGHTS - OH	70	S3	0	0.0143	80	S3	0	0.0125
360-13 & 23-1	LAND & LAND RIGHTS - SUB & UND	70	S3	0	0.0143	70	S3	0	0.0143
361-00-1	STRUCTURES & IMPROVEMENTS	80	O1	-15	0.0144	80	R2	-20	0.0150
362-11-1	STATION EQUIPMENT-IN USE	57	R1.5	-25	0.0219	55	R1.5	-25	0.0227
362-12-1	SUPERVISORY EQUIPMENT	30	R2	-25	0.0417	30	R2	-25	0.0417
362-20-1	STATION EQUIPMENT-HELD	45	S1	-25	0.0278	45	S1	-25	0.0278
362-30-1	STATION EQUIP-ELECTRONICS	32	S0	-25	0.0391	32	S0	-25	0.0391
364-00-1	POLES & FIXTURES	60	L0	-30	0.0217	60	R0.5	-35	0.0225
365-10&20-1	OVHD. CONDUCTORS & DEVICES	65	R0.5	-40	0.0215	70	R0.5	-40	0.0200
366-11&22-1	UNDERGROUND CONDUIT	75	R3	-15	0.0153	80	R4	-10	0.0138
367-00-1	UNDERGROUND COND. & DEVICES	70	R2	-15	0.0164	75	R3	-15	0.0153
368-00-1	TRANSFORMERS	41	S0	-15	0.0280	41	S0	-10	0.0268
369-10-1	OVERHEAD SERVICES	65	R1.5	-65	0.0254	65	R1.5	-60	0.0246
*369-21&22-1	UNDERGROUND SERVICES	65	R1.5	-15	0.0177	65	R1.5	-10	0.0169
370-11&20-1	METERS & INSTALLATION	30	O1	0	0.0333	30	O1	0	0.0333
371-00-1	INSTALLATION ON CUST. PREMISES	30	O2	-15	0.0383	30	O2	-15	0.0383
372-10-1	LEASED PROP. ON CUST. PREMISES	7	R1	5	0.1357	7	R1	5	0.1357
373-00-1	STREET LIGHTS & CONDUCTORS	35	O2	-15	0.0329	35	O2	-15	0.0329
GENERAL PLANT									
390-00-1	STRUCTURES AND IMPROVEMENTS	40	O2	-40	0.0350	40	O2	-40	0.0350

Appendix V, Sheet 2 of 3

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 and 17-G-0460
Depreciation Factors and Rates

		Effective as of 7/1/15				Effective as of 7/1/18			
	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	70	R4	0	0.0143	75	R3	0	0.0133
366-20-2	STRUCTURES & IMPROVEMENTS	50	S1	-55	0.0310	65	S1	-25	0.0192
367-00-2	MAINS	80	R3	-25	0.0156	85	R4	-25	0.0147
369-11-2	STATION EQUIPMENT	40	L0	-25	0.0313	40	L0	-25	0.0313
369-12-2	SUPERVISORY EQUIPMENT	19	L2	-25	0.0658	22	L1.5	-25	0.0568
369-30-2	SUPERVISORY EQUIPMENT - ELECTRONIC	19	L2	-25	0.0658	19	L2	-25	0.0658
DISTRIBUTION									
374-11 & 13-2	LAND & LAND RIGHTS	75	R3	0	0.0133	85	R4	0	0.0118
375-00-2	STRUCTURES & IMPROVEMENTS	55	S1.5	-15	0.0209	55	S1.5	-15	0.0209
376-00-&11, 12,13-2	MAINS	95	R2.5	-45	0.0153	95	R2.5	-45	0.0153
378-11-2	STATION EQUIPMENT	38	L0.5	-45	0.0382	36	L0.5	-45	0.0403
378-12 & 30-2	SUPERVISORY EQUIPMENT	38	L0.5	-45	0.0382	38	L0.5	-45	0.0382
380-00-2	SERVICES	80	R2	-60	0.0200	81	R1.5	-60	0.0198
381-00-2	METERS	28	L1.5	-2	0.0364	28	L1.5	0	0.0357
382-00-2	METER INSTALLATIONS	28	L1.5	-2	0.0364	28	L1.5	0	0.0357
385-00-2	INDUSTRIAL-STATION EQUIPMENT	45	R2	-30	0.0289	45	R2	-30	0.0289
385-10-2	INDUSTRIAL-STATION EQUIPMENT	30	S2.5	-30	0.0433	40	S3.0	-30	0.0325
	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	-55	0.0310	50	S1	-25	0.0250
366-50-2 RL	STRUCTURES & IMPROVEMENTS- **original cost only fully amortized**			-55	0.0110			-55	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	40	L0	-25	0.0313
369-51-2 RL	STATION EQUIPMENT -**original cost only fully amortized**			-25	0.0063			-25	0.0063
369-52-2 ASL	SUPERVISORY EQUIPMENT	19	L2	-25	0.0658	22	L2	-25	0.0568
369-52-2 RL	SUPERVISORY EQUIPMENT- **original cost only fully amortized**			-25	0.0132			-25	0.0132

Appendix V, Sheet 3 of 3

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 and 17-G-0460
Depreciation Factors and Rates

COMMON

		Effective as of 7/1/15				Effective as of 7/1/18			
Account	Account Description	ASL	Curve Type	Net Salv. %	Annual Rate	ASL	Curve Type	Net Salv. %	Annual Rate
390-00 & 11-4	General Structures & Improvements	50	O1	-55	0.0310	50	O1	-55	0.0310
392-10-4	Transportation Equip- Electric	10	L2.5	+10	0.0870	10	L2.5	+10	0.0900
392-20-4	Transportation Equip- Gas	10	L2.5	+10	0.0900	10	L2.5	+10	0.0900
392-40-4	Transportation Equip- Common	10	L2.5	+10	0.0900	10	L2.5	+10	0.0900
396-10-4	Power Operated Equip- Electric	12	L3	+10	0.0750	12	L3	+10	0.0750
396-20-4	Power Operated Equip- Gas	12	L3	+15	0.0708	12	L3	+15	0.0708
396-40-4	Power Operated Equip- Common	12	L3	+15	0.0708	12	L3	+15	0.0708

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	12	SQ	+0	0.0833
391-21-4	Data Handling Equipment	20	SQ	+0	0.0500	20	SQ	+0	0.0500
391-22-4	Office Furniture	20	SQ	+0	0.0500	20	SQ	+0	0.0500
393-00-4	Stores Equipment	35	SQ	+0	0.0286	35	SQ	+0	0.0286
393-20-4	Stores Equipment- Forklifts	35	SQ	+0	0.0286	35	SQ	+0	0.0286
394-10-4	Garage & Repair Equipment	30	SQ	+0	0.0333	30	SQ	+0	0.0333
394-20-4	Shop Equipment	30	SQ	+0	0.0333	30	SQ	+0	0.0333
394-30-4	Tools & Work Equipment	30	SQ	+0	0.0333	30	SQ	+0	0.0333
395-10-4	Laboratory Equipment	35	SQ	+0	0.0286	35	SQ	+0	0.0286
395-20-4	Laboratory Equipment- R&D	35	SQ	+0	0.0286	35	SQ	+0	0.0286
397-10-4	Communication Equipment - Radio	20	SQ	+0	0.0500	20	SQ	+0	0.0500
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	30	SQ	+0	0.0333

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 and 17-G-0460
Earnings Adjustment Mechanisms

Central Hudson will adopt electric and gas Earnings Adjustment Mechanisms ("EAMs") as of July 1, 2018. Achievement of EAMs will be measured on December 31, 2018 and thereafter on a calendar year basis through calendar year 2021. There are five EAMs for electric, comprised of a total of seven metrics, and one EAM for gas, comprised of one metric. Each EAM metric contains targets that are set at minimum, midpoint and maximum performance levels. The Company will earn pre-tax earnings adjustments on a prorated basis for performance between the minimum and midpoint performance levels, and between the midpoint and maximum performance levels. Central Hudson has the potential to earn a maximum earnings adjustment of $2.0 million in 2018, $4.3 million in CY 2019, $4.7 million in CY 2020, and $4.9 million in CY 2021 for its electric business. With respect to the gas business, Central Hudson has the potential to earn a maximum earnings adjustment of $0.18 million in 2018, $0.39 million in CY 2019, $0.44 million in CY 2020, and $0.47 million in CY 2021. The EAMs, targets, and earnings adjustments are described in the sections that follow.

1.0 ELECTRIC EAMS

System Efficiency

The System Efficiency EAM is composed of two metrics: Peak Reduction and Distributed Energy Resources ("DER") Utilization.

1) Peak Reduction

The Peak Reduction EAM metric incentivizes Central Hudson to reduce its New York State Independent System Operator ("NYISO") Zone G-J Locality peak. Achievement of the Peak Reduction metric will be calculated as the sum of:

a) The weather-normalized demand on the Central Hudson system at the hour of the NYISO Zone G-J Locality peak in each measurement period, plus

b) Any amounts actually curtailed from contracted resources enrolled in the New York Independent System Operator's ("NYISO") Installed Capacity – Special Case Resource program during the NYISO Zone G-J Locality peak hour.

The weather normalization described in part a, above, will be based on the Company's annual submission to the NYISO of its weather-normalized NYCA coincident system peak.

2) <u>DER Utilization</u>

The DER Utilization EAM metric incentivizes Central Hudson to work with third parties to expand the use of DER resources in the Company's service territory. This metric will measure the sum of the annualized megawatt hours ("MWh") from incremental DER in Central Hudson's service territory, including large solar, combined heat and power, standalone or behind the meter electric energy storage resources, and fuel cells.

The DER Utilization metric will be calculated as follows:

DER Utilization (MWh) =
Community PV MWh annualized production
+ Combined heat and power ("CHP") MWh annualized production
+ Fuel cell MWh annualized production
+ Battery storage MWh annualized discharge
+ Battery storage MWh annualized charging

Annualized production will be calculated as follows:

Technology	Annualized MWh Calculation
Community PV production	= MW installed * 13.4% capacity factor * hours/yr
CHP production	= MW installed * 85% capacity factor * hours/yr
Fuel cell production	= MW installed * 91% capacity factor * hours/yr
Battery Storage discharge	= [Daily battery inverter discharge rating (MWh)] * [365 days per year]
Battery Storage charging	[Daily battery inverter discharge rating (MWh)] * [365 days per year] / [83% round trip efficiency]

1.1 Electric Energy Efficiency

The Electric Energy Efficiency EAM is composed of three metrics: Electric Energy Efficiency, Residential Electric Energy Intensity, and Commercial Electric Energy Intensity.

1) Electric Energy Efficiency (MWh)

The Electric Energy Efficiency EAM metric incentivizes the Company to achieve energy efficiency savings in calendar years 2018 through 2021 that are significantly above its historical first-year annual savings target of 34,240 MWh. This metric will be measured as the sum of MWh savings from all of Central Hudson's administered electric ETIP energy efficiency programs, including behavioral programs, which may be utilized to achieve MWh targets.

As a precondition to earning the incentive associated with this metric, the Estimated Useful Life ("EUL") of the Company's ETIP portfolio must be at least 90 percent of the current weighted average EUL for New York State utilities of 7.9 years. The Company will earn a linearly prorated share of the incentive if the achieved EUL is greater than 7.9. Where the Company's EUL of its ETIP is greater than or equal to its historical EUL of 10, the Company would be able to earn 100% of this EAM incentive. ETIP savings will be calculated consistent with the current standard practices described in the Company's June ETIP.

The Signatory Parties agree that this Electric Energy Efficiency EAM is subject to change as a result of the Commission's action on Staff's upcoming Earth Day Energy Efficiency Targets/Funding proposal, which is due on or about Earth Day 2018 (April 22, 2018) per Governor Cuomo's State of the State directives and Case 18-M-0084.

2) Residential Electric Energy Intensity

The Residential Electric Energy Intensity EAM metric incentivizes Central Hudson to reduce residential (Service Classes 1 and 6) customers' total usage on a per customer basis. This metric will be measured as the annual residential MWh sales divided by the 12-month average number of residential customers. Within this calculation the annual residential MWh sales will be: 1) normalized to correct for the weather related impacts on electricity sales, 2) reduced by the aggregate MWhs produced by Community Distributed Generation resources and allocated to residential customers through the value stack tariff, and 3) adjusted to exclude the impacts of beneficial electrification such as new load from heat pumps and electric vehicles.

The Residential Electric Energy Intensity metric will be calculated as:

$$\frac{(weather\ normalized\ MWh\ sales) - (MWh\ CDG\ allocations) - (MWh\ sales\ associated\ with\ EVs\ or\ heat\ pumps)}{12\ month\ average\ residential\ customers}$$

Within this formula the following components are defined as follows:

- Weather Normalization Methodology will reflect the weather normalization methodology in Staff's energy intensity exhibits filed within this proceeding.
- MWh CDG allocations will be derived from the process the Company will utilize to apply monetary credits to the customers of CDG facilities that are applicable for Value Stack compensation or any replacement compensation developed within the Value of DER proceeding.
- Annual MWh sales associated with the impacts of identified beneficial electrification technologies are shown below:
    - Electric vehicles ("EV"): 3.9 MWhs
    - Air-source heat pumps ("ASHP") and Ground-source heat pumps ("GSHP"): 4.5 MWhs

3) Commercial Electric Energy Intensity

The Commercial Electric Energy Intensity EAM metric incentivizes Central Hudson to reduce commercial (Service Class 2 non demand) customers' total usage on a per customer basis. This metric will be measured as the annual commercial MWh sales divided by the 12-month average number of commercial customers. Within this calculation the annual commercial MWh sales will be: 1) normalized to correct for the weather related impacts on electricity sales, 2) reduced by the aggregate MWhs produced by Community Distributed Generation resources and allocated to commercial customers through the value stack tariff, and 3) adjusted to exclude the impacts of beneficial electrification such as new load from heat pumps and electric vehicles.

The Commercial Electric Energy Intensity metric will be calculated as:

$$\frac{(weather\ normalized\ MWh\ sales) - (MWh\ CDG\ allocations) - (MWh\ sales\ associated\ with\ EVs\ or\ heat\ pumps)}{12\ month\ average\ commercial\ customers}$$

Within this formula the following components are defined as follows:

- Weather Normalization Methodology will reflect the weather normalization methodology in Staff's energy intensity exhibits filed within this proceeding.
- MWh CDG allocations will be derived from the process the Company will utilize to apply monetary credits to the customers of CDG facilities that are applicable for Value Stack compensation or any replacement compensation developed within the Value of DER proceeding.
- Annual MWh sales associated with the impacts of identified beneficial electrification technologies are shown below:
    - Electric vehicles ("EV"): 3.9 MWhs
    - Air-source heat pumps ("ASHP") and Ground-source heat pumps ("GSHP"): 1.5 MWhs per ton based on system size.

1.2 Customer Engagement EAM

The Customer Engagement EAM incentivizes the Company to increase customer participation in Voluntary Time of Use ("VTOU") rates. The Customer Engagement EAM measures the percentage of Central Hudson's residential customers that sign up for VTOU rates. This metric will be measured as the sum of the number of customers participating in the Company's SC 6 VTOU rates and the number of customers participating in the Company's Smart Home Rate Demonstration Project, divided by the total number of residential customers. This metric will be measured on December 31 of each respective calendar year.

1.3 Environmentally Beneficial Electrification

The Environmentally Beneficial Electrification EAM metric incentivizes the Company to reduce carbon emissions by facilitating greater penetration of technologies that utilize electricity and reduce carbon emissions relative to traditional technologies that rely on carbon intensive fuel sources. Examples of these technologies include geothermal heating, air source heat pumps for heating, and electric vehicles. The metric will be measured as the lifetime short tons of avoided carbon dioxide from environmentally beneficial electrification technologies as identified in the Company's Carbon Reduction Implementation Plan, which will be filed within 30 days of the Commission's issuance of a final order in this proceeding. Future Carbon Reduction Implementation Plans ("CRIP") will be filed coincident with the Company's ETIP filings. During Rate Year 1, the Company will evaluate electric vehicle programs to be included in the Carbon Reduction Implementation Plan filed in June 2019.

Until other applicable technologies are identified within a future Carbon Reduction Implementation Plan, the Environmentally Beneficial Electrification EAM will be measured as the incremental lifetime short tons of avoided carbon dioxide ("CO2") from incremental electric vehicles and heat pumps. Incremental lifetime tons of CO2 will be calculated as the number of incremental units multiplied by the assumed avoided tons of CO2 multiplied by the average technology life as agreed to below.

Electric vehicles ("EV"): *EV registrations * 3.8 tons CO2 * 10 years*
Air-source heat pumps ("ASHP"): *ASHP installations * 6.7 tons CO2 * 15 years*

Ground-source heat pumps ("GSHP"): *GSHP installations * 6.7 tons CO2 * 25 years*

The EV component of the Environmentally Beneficial Electrification metric is an outcome based metric and will be measured as the incremental electric vehicles registered in Central Hudson's service territory. Electric vehicles are defined as battery electric vehicles ("BEVs") and Plug-in hybrid vehicles ("PHEVs"). Data will be obtained from the HIS Markit Vehicle Market Analysis: Registrations and Vehicles-in-Operation.[1] Quantification of the ASHP component of the Environmentally Beneficial Electrification metric will be determined through participation in Central Hudson's Carbon Reduction Program. Quantification of the GSHP component of the Environmentally Beneficial Electrification metric will be determined by the number of Central Hudson customers participating in NYSERDA geothermal rebate program, receiving the Central Hudson Rate Impact Credit, or participation in Central Hudson's Carbon Reduction Program.

1.4 Interconnection

The Company may petition the Commission for approval of metrics and targets consistent with a future Commission order regarding the Interconnection EAM Metric in Case 16-M-0429 - In the Matter of Earnings Adjustment Mechanism and Scorecard Reforms Supporting the Commission's Reforming the Energy Vision. The Company will reserve 1 BP Minimum, 2.5 BP Midpoint, and 5 BP at Maximum for Interconnection-related EAMs in total.

[1] Or a comparable data source. Any change in source data to be noted in future CRIP filings.

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 and 17-G-0460
Earnings Adjustment Mechanisms

1.5 Electric EAM Targets and Incentives

The annual electric EAM minimum, midpoint, and maximum targets and associated positive revenue adjustments are as follows:

Electric EAMs		**Incentive ($)**				**Target**			
Metric (Unit)		2018	2019	2020	2021	2018	2019	2020	2021
Peak Reduction (MW)	Min	65,000	136,800	150,300	157,000	1,091	1,079	1,046	1,022
	Mid	162,500	342,000	375,750	392,500	1,083	1,065	1,026	997
	Max	325,000	684,000	751,500	785,000	1,072	1,042	990	949
DER Utilization (MWh)	Min	32,500	68,400	75,150	78,500	4,837	5,243	5,649	6,054
	Mid	97,500	205,200	225,450	235,500	5,522	5,928	6,333	6,739
	Max	162,500	342,000	375,750	392,500	6,207	6,612	7,018	7,424
Energy Efficiency (MWh)	Min	130,000	273,600	300,600	314,000	47,936	47,936	47,936	47,936
	Mid	227,500	478,800	526,050	549,500	57,292	57,292	57,292	57,292
	Max	487,500	1,026,000	1,127,250	1,177,500	71,192	71,192	71,192	71,192
Residential Energy Intensity (MWh/customer)	Min	81,250	171,000	187,875	196,250	7.68	7.60	7.52	7.44
	Mid	162,500	342,000	375,750	392,500	7.59	7.51	7.44	7.36
	Max	243,750	513,000	563,625	588,750	7.51	7.43	7.35	7.27
Commercial Energy Intensity (MWh/customer)	Min	81,250	171,000	187,875	196,250	48.24	47.90	47.56	47.22
	Mid	162,500	342,000	375,750	392,500	48.05	47.71	47.36	47.02
	Max	243,750	513,000	563,625	588,750	47.85	47.51	47.17	46.83
Residential VTOU Participation (%)	Min	32,500	68,400	75,150	78,500	1.51%	2.76%	3.99%	5.21%
	Mid	97,500	205,200	225,450	235,500	2.13%	3.87%	5.60%	7.32%
	Max	162,500	342,000	375,750	392,500	2.74%	4.99%	7.22%	9.43%
EBE (Lifetime Tons CO_2)	Min	81,250	171,000	187,875	196,250	4,257	8,514	8,514	8,514
	Mid	162,500	342,000	375,750	392,500	12,123	24,245	24,245	24,245
	Max	243,750	513,000	563,625	588,750	19,988	39,976	39,976	39,976
Interconnection (Developer Satisfaction)	Min	32,500	68,400	75,150	78,500				
	Mid	81,250	171,000	187,875	196,250	TBD			
	Max	162,500	342,000	375,750	392,500				
Total Potential Electric EAM Incentive	Min	536,250	1,128,600	1,239,975	1,295,250				
	Mid	1,153,750	2,428,200	2,667,825	2,786,750				
	Max	2,031,250	4,275,000	4,696,875	4,906,250				

2.0 GAS EAMS

2.1 Gas Energy Efficiency

The Gas Energy Efficiency EAM incentivizes the Company to achieve energy efficiency savings that are significantly above its historical first-year annual savings target of 37,296 Dth for calendar years 2018 through 2021. This metric will be measured as the sum of Dth savings from all of Central Hudson's administered gas ETIP energy efficiency programs. As a precondition to earning this incentive, the EUL of the Company's ETIP portfolio must be at or greater than 90% of its historical EUL of 9.4. The Company will earn a linearly prorated share of the incentive if the achieved EUL is greater than 9.4 up to 100% achieved at an EUL of 10.4. Where the Company's EUL of its Gas ETIP portfolio is greater than or equal to its historical EUL of 10.4, the Company would be able to earn 100% of this EAM incentive. ETIP savings will be calculated consistent with the current standard practices described in the Company's June ETIP.

The Signatory Parties agree that this Gas Energy Efficiency EAM is subject to change as a result of the Commission's action on Staff's upcoming Earth Day Energy Efficiency Targets/Funding proposal, which is due on Earth Day 2018 (on/about April 22, 2018) per Governor Cuomo's State of the State directives and Case 18-M-0084.

2.2 EAM Targets and Positive Revenue Adjustments

The annual gas EAM minimum, midpoint, and maximum targets and associated positive revenue adjustments are as follows:

Gas EAMs		**Incentive ($)**				**Target**			
Metric (Unit)		2018	2019	2020	2021	2018	2019	2020	2021
Energy Efficiency (Dth)	Min	60,000	128,750	146,500	155,500	52,214	52,214	52,214	52,214
	Mid	120,000	257,500	293,000	311,000	61,978	61,978	61,978	61,978
	Max	180,000	386,250	439,500	466,500	79,080	79,080	79,080	79,080

3.0 EAM REPORTING REQUIREMENTS

The Company will file annual EAM reports with the Secretary no later than March 1 of each year setting forth the Company's performance relative to each EAM metric target; savings and benefits achieved; calculations for incentives earned including proration of any incentives related to metric achievement between the minimum, midpoint, and the maximum target levels;

and explanations for any targets not achieved. The Company will also file with the Secretary quarterly reports no later than sixty days after the end of each calendar quarter to describe the Company's progress toward each EAM's metric target, the actions taken by the Company to achieve target performance, and a forecast of whether the Company expects to meets its annual EAM targets. The annual EAM report will also include the derivation of the EAM incentive amounts to be recovered from each service class/sub-class utilizing the allocation methodologies described in Section 4.0 herein.

The Company will also file with the Secretary a mid-point review of its EAMs not later than March 1, 2020 in these proceedings. In its mid-point review filing, the Company will evaluate capacity factors of solar and combined heat and power, and, if necessary, propose to revise targets and calculations going forward. Any proposed revisions to targets are subject to Commission approval.

4.0 RECOVERY OF EAM INCENTIVES

4.1 Recovery of Electric EAM Incentives

Incentives associated with Electric EAMs will be recovered through the Miscellaneous Charges EAM Factor, which will be a component of the Company's Energy Cost Adjustment Mechanism. Recovery will be over a twelve month period commencing with the first billing batch of July. Recovery will be on a kWh basis for non-demand customers and on a kW basis for demand customers, with rates determined for each service classification or sub-classification based on the aggregate results of the following allocation methodologies divided by either forecast kWh or kW over the respective recovery period:

- Peak Reduction EAM: allocated using the transmission demand allocator;

- Energy Efficiency, Energy Intensity and Environmentally Beneficial Electrification EAMs: allocated using the energy allocator; and,
- DER Utilization EAM: allocated using three allocators which will be equally weighted: coincident peak, non-coincident peak, and energy allocator.

These rates will be applied to the energy (kWh) or demand (kW) deliveries, as applicable, on the bills of all customers served under Service Classification Nos. 1, 2, 3, 5, 6, 8, 9, 13, and 14. Customers taking service under Service Classification No. 14 will be billed the rate applicable to their Parent Service Classification, which is the Service Classification that the customer would otherwise qualify for based on the customer's usage characteristics.

Recoveries (eleven months actual, one month forecast) will be reconciled to allocable costs for each twelve month recovery period ending June 30, with any over or under recoveries included in the development of succeeding Miscellaneous Charges EAM Factors. Reconciliation amounts related to the one month forecast will be included in the next subsequent rates determination.

For billing purposes, recovery for non-demand customers will be included in the Miscellaneous Charges, with the combined amount shown as one line item on customer bills. Cost recovery for demand customers will be through the Miscellaneous Charges II, a separate line item on customer bills.

4.2 Recovery of Gas EAM Incentives

Incentives associated with Gas EAMs will be recovered through the new Gas Miscellaneous Charge mechanism described in Section XII.K. herein. Recovery will be over a twelve month period commencing with the first billing batch of July. Recovery will be on a Ccf basis with a uniform factor developed, based on forecast Ccf over the respective recovery period, and applied to all deliveries on the bills of all customers served under Service Classification Nos. 1, 2, 6, 11, 12, 13, 15 and 16. Recoveries (eleven months actual, one month forecast) will be reconciled to allocable costs for each twelve month recovery period ending June 30, with any over or under recoveries included in the development of succeeding Miscellaneous Charges EAM Factors. Reconciliation amounts related to the one month forecast will be included in the next subsequent rates determination.

Central Hudson Gas & Electric Corporation
Cases 17-E-0459 and 17-G-0460
NWA Incentive Mechanism

1. Overview

The Company will continue to earn, record, and report incentives associated with its current NWA Programs as authorized by the Order Implementing with Modification the Proposal for Cost Recovery and Incentive Mechanism for Non-Wire Alternative Project issued on July 15, 2016 in Case 14-E-0318 and the subsequent Operating and Accounting Procedures filed with the Secretary as directed within that Order. Within this proceeding a new NWA Incentive Mechanism establishes an incentive mechanism for future NWA Projects implemented following the Commission's issuance of a final order in these proceedings. The new NWA Incentive Mechanism institutes separate but similar methodologies for determining incentives applicable to Large Projects[1] and Small Projects.[2] Through the NWA Incentive Mechanism, the Company may retain a share of the present value of net benefits identified by comparing an NWA project to the traditional infrastructure project it would defer or replace based on a BCA.[3] The incentive amount available to the Company will be adjusted based on the difference between the forecast cost of achieving deferral

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[1] A Large Project for NWA consideration is one where the estimated capital cost of the traditional infrastructure investment to be deferred is greater than or equal to $1 million. Large Projects generally require a larger number of MWs and have a longer lead time.

[2] A Small Project for NWA consideration is one where the estimated capital cost of the traditional infrastructure investment to be deferred is greater than $500,000 but less than $1 million. The need for Small Projects tends to develop more rapidly, and therefore they require a streamlined process for rapid response.

[3] The Company may pursue multiple NWA projects to defer separate traditional infrastructure projects in the same area.

and the actual costs of such. In the event the number of megawatts ("MWs") required to defer the traditional project increases or decreases, the incentive amount would be further adjusted. The NWA Incentive Mechanism provides an incentive floor of $0 and a cap of 50% of the initially-identified net benefits.

NWA project costs will be deferred with carrying costs.[4] Recovery of such costs will be amortized over a 10-year period, with offsetting credits to the extent that an NWA project defers the need for a traditional infrastructure project included in the Company's Average Electric Plant in Service Balance.

2. Benefit Cost Analysis

For Large Projects, the Company will use a full-scale BCA to compare the present value of the net costs and benefits of an NWA project versus the present value of the net costs and benefits of a traditional infrastructure project. The BCA will consider all of the benefit and cost categories described in the BCA Order and use the Company's BCA Handbook. For Small Projects, the Company will use a "streamlined" BCA, which will include the major categories of costs and benefits outlined in the BCA Order, but will not include non-energy benefits, other than carbon dioxide reductions, or any benefits which might otherwise be realized by implementing a traditional infrastructure solution.

3. NWA Incentive Mechanism Applicable to Large Projects

The Company will establish an initial incentive ("Initial Incentive") equal to 30% of the present value of net benefits ("Initial Net Benefits"), i.e., the present

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4 Carrying costs shall be at the PTROR.

value of net benefits projected at the time the Company has either entered into contracts with DER providers for the NWA project portfolio, or when there is reasonable certainty on the price of the NWA project portfolio. To establish the Initial Incentive, the Company shall make a compliance filing. Prior to making its compliance filing to set the Initial Incentive, the Company shall seek input from Staff. Once the NWA project has been fully implemented, the Company will calculate the difference in the net present value ("NPV") of the NWA Project Cost, which will be equal to the NPV of the initially-forecasted NWA project cost, less the NPV of the actual NWA project. The Final Incentive will equal the sum of the Initial Incentive and ±50% of the difference in the NPV of the NWA Project Cost. The Final Incentive is subject to a floor of $0 and a cap of 50% of the Initial Net Benefits. Both the Initial Incentive and the Final Incentive calculations are subject to change based on Staff's review and audit.

Should additional MWs be needed to achieve the initially proposed deferral of a traditional infrastructure project or to increase the duration of the deferral, the Company will make a compliance filing and seek incremental MW procurements accordingly. So long as it is feasible and remains cost-beneficial to procure the additional MWs to continue deferral, the Company will be authorized to receive cost recovery of the expenditures incurred in obtaining the additional MWs, including carrying charges. However, the Company's Final

Incentive would not reflect either the costs[5] or the benefits associated with the additional MWs. In the event the Company determines that acquiring additional MWs is technically or operationally infeasible, it will plan to implement a traditional infrastructure solution. Recovery of any incentives related to that project will be halted without requiring a refund of the amounts already collected at that time.

In the event fewer MWs are needed to achieve the intended deferral of traditional infrastructure, the Company will only reduce the number of MWs it plans to procure if both the need for reduced MWs is shown to be a sustained downward trend over a three-year period and the Company needs only 70% or fewer of the initially-forecasted MWs to achieve the intended deferral. The Company will true-up the incentive by converting the Initial Incentive to an Initial Unit Incentive by dividing its 30% share of Initial Net Benefits by the initial number of MWs it forecasted. Similarly: (1) the Difference in the net present value of the NWA Project Cost to achieve deferral will be calculated on a per-MW basis; and (2) the Unit Difference in NWA Project Cost will be calculated by dividing the net present value impact of the change in NWA Project Cost by the number of MWs required. The Final Incentive will be calculated as the sum of the Initial Unit Incentive plus or minus the Unit Difference in NWA Project Cost, multiplied by the reduced amount of MWs determined to be necessary, subject to

[5] The expenditures related to acquiring such additional MWs will not be considered in the Difference in NWA Project Cost used to calculate the Final Incentive.

the same 50% share of Initial Net Benefits incentive cap and $0 incentive floor provisions.

4. NWA Incentive Mechanism Applicable to Small Projects

Similar to Large Projects, the Initial Incentive related to Small Projects will be based on a 30% share of the present value of net benefits ("Initial Net Benefits"), i.e., the present value of net benefits projected at the time the Company has either entered into contracts with DER providers for the NWA project portfolio or when there is reasonable certainty on the price of the NWA project portfolio. For Small Projects, however, the Initial Incentive will be set on a per MW basis. This Initial Unit Incentive is calculated by dividing the 30% share of Initial Net Benefits by the number of MWs to be procured for the NWA project. To establish the Initial Unit Incentive, the Company shall make a compliance filing in Case 17-E-0459. Prior to making its compliance filing to set the Initial Unit Incentive, the Company shall seek input from Staff. Once the NWA project has been fully implemented, the Company will calculate the Unit Difference in the NPV of the NWA Project Cost, equal to the initially-forecasted cost of the NWA project minus the actual cost of the NWA project, divided by the number of MWs required. The Final Incentive will be determined by adding the Unit Difference in the net present value of the NWA Project Cost to the Initial Unit Incentive, multiplied by the MWs required.

For Small Projects, the Company will consider its need for more or fewer MWs using an annual analysis. Should additional MWs be needed to achieve the initially proposed deferral of a traditional infrastructure project or to increase the duration of the deferral, the Company will make a compliance filing in Case 17-E-0459 and seek incremental MW procurements accordingly. So long as it is feasible and remains cost-beneficial to procure the additional MWs to continue deferral, the Company will be authorized to receive cost recovery of the expenditures incurred in obtaining the additional MWs, including carrying charges. However, the Company's Final Incentive would not reflect either the costs[6] or the benefits associated with the additional MWs. In the event the Company determines that acquiring additional MWs is technically or operationally infeasible, it will plan to implement a traditional infrastructure solution. Recovery of any incentives related to that project will be halted without requiring a refund of the amounts already collected at that time.

If the annual needs assessment determines that fewer MWs are required to achieve the intended deferral of traditional infrastructure, the Company will only seek to decrease its procurements if it determines that it needs only 70% or fewer of the initially-forecasted MWs to achieve the intended deferral. In the event of a reduction in the number of MWs required, the Unit Difference in NWA Project Cost will be calculated as if the MW reduction did not occur. The Final Incentive, however, will be calculated as the sum of the Initial Unit Incentive and the Unit Difference in the net present value of the NWA Project Cost, multiplied

[6] The expenditures related to acquiring such additional MWs will not be considered in the Difference in NWA Project Cost used to calculate the Final Incentive.

by the reduced amount of MWs determined to be necessary, subject to the same 50% share of Initial Net Benefits incentive cap and $0 incentive floor provisions.

5. NWA Cost and Incentive Recovery

Consistent with the Order Adopting a Ratemaking and Utility Revenue Model Policy Framework issued on May 19, 2016 in the REV Proceeding,[7] the Company's Net Plant Reconciliation Mechanism is revised to remove the financial disincentive utilities face when engaging in NWA projects. To the extent an NWA project results in the Company displacing a capital project that is reflected in the Average Electric Plant in Service Balances, the balance(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge associated with the displaced project will be applied as a credit against the recovery of the associated NWA project cost to be recovered from customers. In the event the carrying charge on the net plant of any displaced project is higher than the recovery of the associated NWA project costs, the difference will be deferred for the benefit of customers.

NWA project costs and the Final Incentive under the NWA Incentive Mechanism will be allocated to each service classification based on the following allocators from the most recent rate year proforma embedded cost of service study: (1) coincident peak demand (summer) for the system transmission portion (if any) of the deferred traditional project; and (2) a non-coincident peak ("NCP")

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[7] Case 14-M-0101 - Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (May 19, 2016).

demand allocator for the sub-transmission and distribution portions of the deferred traditional project, including NCP – Common Transmission Lines, Class NCP – General Transmission, Class NCP at Primary, Sigma NCP at Secondary, and Class NCP at Distribution Substation. For example, the costs and incentives related to an NWA project which defers the need for general subtransmission line infrastructure would be allocated to SCs based on their Class NCP – General Transmission demand allocator. Similarly, the costs and incentives related to an NWA project which defers the need for primary-voltage distribution line infrastructure would be allocated to SCs based on their Class NCP at Primary demand allocator. If an NWA project will benefit only certain classes of customers, the cost allocation will be limited to the benefitted service classifications.

Once allocated to each service classification, these costs would be recovered through a separate component of the existing Miscellaneous Charges portion of the Energy Cost Adjustment Mechanism following the rate development process of the current Miscellaneous Charges II Factor. Such rates will be determined on a kWh basis for non-demand customers and on a kW basis for demand customers, filed with the Commission on the Statement of Miscellaneous Charges and, for billing purposes included in the Miscellaneous Charges line item for non-demand customers and the Miscellaneous Charges II line item for demand customers.

6. Amortization of New NWA Project Costs and Incentives

The Company will recover its NWA project costs over a 10-year period. The 10-year recovery period will begin when the NWA project costs are realized. Any unamortized costs plus carrying charges will be incorporated into base rates when electric base rates are reset.

For Large Projects, the Company will be awarded and begin collecting the Final Incentive from customers once 70% of the MWs it procured for the NWA project have become operational and have been verified through the Company's measurement and verification procedures. For Small Projects requiring more than one MW of DER, the Company will be awarded and begin collecting an amount equal to the Initial Unit Incentive as each MW of the NWA portfolio becomes operational. For Small Projects less than one MW of DER, the Company will be awarded and begin collecting the Final Incentive once the NWA project portfolio is operational. For both Large and Small Projects, once awarded, the Company will amortize the Final Incentive of an NWA project over the remaining deferral period for the traditional infrastructure project, inclusive of carrying costs on the unamortized balance of the Final Incentive.

7. Reporting Requirements

The Company will submit a detailed implementation plan and BCA for each NWA project portfolio once there is reasonable certainty as to the costs of the NWA project portfolio. The implementation plan for each NWA will include, at a minimum: (1) detailed measurement and verification procedures; (2) the portfolio of component load reductions or DER to be implemented; (3) the anticipated costs of the NWA; (4) a demonstration of whether the costs of the NWA projects are incremental to the Company's revenue requirement or will be displacing a project subject to the Net Plant Reconciliation Mechanism; (5) a customer and community outreach plan; and (6) the BCA results when available. The implementation plan for each project will be updated at least annually; however, the Company will also update relevant plans promptly if it determines it needs to increase or decrease the number of MWs required to effectuate an NWA project or if the length of the deferral period for the traditional infrastructure solution associated with the NWA is modified. Annual implementation plans will be filed by January 31 of each year. If the number of MWs or length of deferral is modified, the Company shall also file an updated BCA as appropriate.

In addition, the Company also will file quarterly reports showing: (1) NWA project expenditures and all relevant details with respect to project costs; (2) a description of the NWA project activities; (3) anticipated project in-service dates; (4) NWA cost and incentive recoveries; and (5) operational savings or other benefits. The quarterly reports shall be filed 60 days after the close of each calendar year quarter.

Appendix Y
Central Hudson Gas & Electric Corporation
Cases 17-E-0459 & 17-G-0460

2018- 2021 Construction Forecast ($000's)
(with inflation & OH adjustment)

		2018	2019	2020	2021	2018-2021 Total
ELECTRIC PROGRAM						
Hydro & Gas Turbines	**11**	1,910	2,084	1,554	1,647	7,195
Transmission	**12**	19,458	19,522	21,713	23,532	84,225
Substations	**13**	16,185	19,443	19,951	18,535	74,114
New Business	**14**	6,520	6,818	7,051	7,285	27,675
Dist. Improvements	**15**	35,759	41,166	40,424	39,952	157,302
Transformers	**16**	5,358	5,603	5,809	5,923	22,693
Meters	**17**	2,383	2,490	2,635	2,682	10,190
Total Electric Program		87,574	97,127	99,137	99,557	383,394
GAS PROGRAM						
Production	**21**	-	-	-	-	-
Transmission	**22**	2,717	1,763	1,582	2,393	8,455
Regulator Stations	**23**	1,743	2,079	2,443	2,644	8,909
New Business	**24**	9,427	9,727	9,881	10,088	39,123
Dist. Improvements	**25**	38,631	40,467	38,780	40,955	158,833
Meters	**27**	2,895	3,001	2,902	2,537	11,334
Total Gas Program		55,414	57,036	55,588	58,616	226,654
COMMON PROGRAM						
Buildings	**41**	8,250	16,017	9,027	17,463	50,758
Buildings Minors		3,871	4,235	4,276	4,463	16,846
Major Expansion		4,379	11,782	4,751	13,000	33,912
Office Equipment	**42**	20,449	26,485	20,517	20,764	88,215
General	**421**	306	168	323	220	1,017
EMS	**423**	2,055	5,349	220	180	7,804
EDP	**4222**	3,113	3,078	3,100	3,165	12,456
Software	**4220**	14,270	17,263	16,240	16,545	64,318
Security	**424**	704	627	635	654	2,620
Tools	**43**	1,285	1,285	1,447	1,394	5,411
Communication	**44**	8,242	9,201	6,695	2,459	26,596
Transportation	**45**	8,297	8,919	9,516	9,316	36,048
Total Common Program		46,523	61,906	47,203	51,396	207,028
CORPORATE TOTAL		189,510	216,070	201,929	209,569	817,077
REMOVALS		9,331	9,163	10,625	10,216	39,334
TOTAL CAPITAL		198,840	225,233	212,554	219,784	856,411