STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service	Case 14-E-0318
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	Case 14-G-0319

JOINT PROPOSAL

February 6, 2015

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JOINT PROPOSAL

I. INTRODUCTION

This Joint Proposal 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"),[1] Pace Energy and Climate Center ("Pace"), Sabin Center for Climate Change Law at Columbia Law School ("Sabin"), the Retail Energy Supply Association ("RESA"), and the other entities whose signatures appear below (collectively, the "Signatories").

[1] Multiple Intervenors is an association of approximately 60 industrial, commercial and institutional energy consumers with manufacturing and other facilities located throughout New York State, including Central Hudson's service territory.

A. Background

On June 18, 2010, the New York State Public Service Commission ("Commission" or "PSC") issued an Order Establishing Rate Plan[2] establishing a three-year rate plan for the Company for the period from July 1, 2010 through June 30, 2013 ("2010 Rate Order").

The Commission issued an Order Authorizing Acquisition Subject to Conditions ("Acquisition Order") on June 26, 2013, approving the indirect acquisition of Central Hudson by Fortis, Inc., a Canadian holding company.[3] Under the Acquisition Order, Central Hudson was subject to a two-year rate freeze. As such, the Company did not seek to adjust delivery rates effective July 1, 2013 at the conclusion of the rate plan authorized under the 2010 Rate Order until the filing of the present rate cases.

B. Filing of the Present Cases

Central Hudson filed with the PSC on July 25, 2014, proposed tariff leaves and its direct testimony 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, 2016 ("Rate Year"). Central Hudson also included select financial information for two additional rate years as Attachment B to its filing letter.[4] Central Hudson's proposed delivery rates were designed to produce an electric delivery base revenue increase of

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[2] Case 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).

[3] 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).

[4] Case 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, Cover Letter Attachment B (July 25, 2014).

approximately $40.1 million and a gas delivery base revenue increase of approximately $5.9 million, resulting in delivery revenue increases of 14.8% and 7.4%, respectively, or total bill increases of 8.4% and 2.7%, respectively, for an average residential customer.[5]

On August 1, 2014, the Commission suspended the Company's proposed tariff leaves through December 21, 2014.[6] Discovery was commenced by Staff and other parties. To date, Staff has tendered a total of 846 multi-part information requests to the Company; the Utility Intervention Unit of the Department of State, Division of Consumer Protection ("UIU") tendered 151; MI tendered 154; Pace tendered 108; the County of Dutchess tendered 33; Citizens for Local Power ("CLP") tendered 21; and Sabin tendered 106. Various other parties also tendered more limited volumes of discovery to the Company.

On September 8, 2014, a Procedural and Technical Conference was held by Administrative Law Judge ("ALJ") Ben Wiles[7] during which, among other things, a litigation schedule was proposed and adopted in a subsequent ruling.[8] On September 30, 2014, an additional procedural conference was held to discuss the status of discovery. At the procedural conference, ALJ Wiles directed the Company to file redacted versions of the Confidential Information the Company had filed on August 5, 2014. The Company had requested exemption from public disclosure of the Confidential Information pursuant to the New York State Freedom of Informational Law

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5 The Company did not propose in testimony to assume responsibility for administering its current suite of energy efficiency programs as part of base rates and as a result, these increases did not include any revenue requirement required for these programs.

6 Case 14-E-0318 et. al., Notice of Suspension of Effective Dates of the Major Rate Changes and Initiation of Proceedings (Aug. 1, 2014). By notice issued Nov. 26, 2014 the Commission further suspended those tariffs through June 21, 2015.

7 ALJ David Prestemon was subsequently assigned along with ALJ Wiles to these proceedings.

8 Case 14-E-0318 et. al., Ruling on Schedule and Granting Party Status (Sept. 16, 2014).

("FOIL") (Public Officers Law § § 84, *et seq.*)[9], and the Company subsequently filed a supplemental response further describing Central Hudson's basis for protecting the Confidential Information. The Company provided the information in a letter to ALJ Wiles dated October 23, 2014.

Staff, MI, UIU, Solar City Corporation ("Solar City"), the County of Dutchess, NRG Energy, Inc. ("NRG"), Pace and Sabin filed direct testimony on November 21, 2014. Central Hudson, Staff, Pace and CLP subsequently filed rebuttal testimony on December 19, 2014.

Consistent with the Commission's Settlement Guidelines[10] and Title 16 of the New York Codes, Rules and Regulations ("NYCRR"), Section 3.9, the Company filed with the Commission and served on all parties a Notice of Impending Settlement Negotiations on November 25, 2014.[11] Settlement negotiations began on December 2, 2014 and continued on December 4, 9, 10, 11, 15, 17, and 18, 2014 and on January 7, 12, 16, 21, 29, and 30, 2015 and February 3, 4, 5, and 6, 2015. Participants included representatives of the Company, Staff, UIU, MI, Solar City, CLP, NRG, Pace, and numerous other interested parties. Negotiations were held either in person or via teleconference. All settlement negotiations were subject to the Commission's

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9 Case 14-E-0318 et. al., Request for Exemption from Disclosure (Aug. 5, 2014). Specifically, the Company sought protection for an exhibit to the Direct Testimony of the Finance Panel which contained confidential/trade secret reports of various credit rating agencies ("Confidential Information").

10 32 NYPSC 71; Case 90-M-0255 et al. - Proceeding on Motion of the Commission Concerning its Procedures for Settlement and Stipulation Agreements, filed in C11175, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines, Opinion 92-2 (Mar. 24, 1991) ("Settlement Guidelines").

11 Case 14-E-0318 et. al., Notice of Impending Settlement Negotiations (Nov. 25, 2014).

Settlement Rules, 16 NYCRR Section 3.9, and the Commission's Settlement Guidelines.

On December 23, 2014, a Further Ruling on Schedule was issued revising the date on which evidentiary hearings in these cases would begin to February 10, 2015 and requiring the parties to file a joint proposal by February 6, 2015 in the event that a settlement was negotiated.[12]

The Parties' settlement negotiations have been successful and have resulted in this Joint Proposal ("JP"), 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 the Company's electric and gas service. Pursuant to the Parties' settlement discussions, the Signatories recommend that the rates and surcharges of the Company be determined in accordance with the understandings, principles, qualifications, terms and conditions set forth in this JP and in the attached Appendices.

II. TERM

A. Agreement Term

The term of this JP is three years, commencing July 1, 2015 and continuing until June 30, 2018. The three successive twelve-month periods, or Rate Years, ending on June 30th 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, 2015 through June 30, 2016). Rate Year 2 (July 1, 2016 through June 30, 2017) and Rate Year 3 (July 1, 2017 through June 30, 2018) will follow the same structure as Rate Year 1 at revenue and expense amounts

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[12] Case 14-E-0318 et. al., Further Ruling on Schedule (Dec. 23, 2014); Case 14-E-0318 et. al., Ruling Errata (Dec. 30, 2014).

as agreed to by the Signatories as set out in the JP. 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, 2018, for rates to be effective on or after June 30, 2018. Except for minor rate changes and Commission-required rate changes permitted by Section XVIII of this JP, the Company will not initiate rate changes to become effective prior to June 30, 2018.

III. 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 for electric and gas service are shown in the table below:[13]

	Rate Year 1 ($000,000)	Rate Year 2 ($000,000)	Rate Year 3 ($000,000)
Electric	$20.203	$20.821	$13.986
Gas	$2.548	$5.330	$4.344

[13] The delivery revenue increases shown include the impact of moving 50% of the costs of Central Hudson programs currently recovered in EEPS2 into base rates in Rate Year 1 and 100% of such costs in Rate Year 2 and Rate Year 3.

C. Electric Bill Credits

To achieve rate moderation, electric bill credits of $13.0 million in Rate Year 1; $12.0 million in Rate Year 2; and $2.0 million in Rate Year 3 will be applied utilizing 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 kilowatt-hour or kilowatt basis, consistent with the manner in which each class is billed.

D. Gas Bill Credits

To achieve rate moderation, in a manner similar to the electric bill credits, gas bill credits of $2.548 million in Rate Year 1 and $1.7 million in Rate Year 2 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, consistent with the manner in which each class is billed.

To the extent that the Company receives gas delivery revenues from the Danskammer Generating Station ("Danskammer") in Rate Year 1, 50% of those revenues will be refunded via a bill credit to the Company's gas customers in Rate Year 2. Similarly, 50% of the gas delivery revenues received from Danskammer in Rate Year 2 will be refunded via a bill credit to the Company's gas customers in Rate Year 3. All gas delivery revenues received from Danskammer in Rate Year 3 will be deferred for the future benefit of the Company's gas customers. The 50% gas delivery revenues remaining from Rate Years 1 and 2 will be deferred for the future benefit of the Company's gas customers. Notwithstanding the general gas bill credit applicable to non-Danskammer actual delivery revenues set forth above, all Danskammer gas delivery revenue related bill credits will be allocated to each service class in proportion to its contribution to overall gas delivery revenue. The allocated credits will be refunded to the Company's gas customers on a Ccf basis, consistent with the manner in which each class is billed.

E. Major Provisions Incorporated into Development of Revenue Requirements

1. Labor Headcount

The Labor expense line item reflected in the Income Statements set forth in Appendix A reflects a headcount of 950 full-time employees ("FTEs") in Rate Year 1; 961 FTEs in Rate Year 2; and 965 FTEs in Rate Year 3. Labor expense also reflects 27 temporary employees throughout the Rate Plan. In addition, 11 additional employees needed for monthly billing are reflected in the Transition to Monthly Billing line item.

2. Distribution and Transmission Right-of-Way ("ROW") Tree Trimming

The electric income statements incorporate funding for transmission and distribution ROW maintenance as set forth in Appendix A.

3. Transition to Monthly Billing

The Transition to Monthly Billing line item reflected in the Income Statements set forth in Appendix A incorporates the costs and expenses the Company will incur to transition from its current bi-monthly billing of certain classes of customers to monthly billing for all customers.

4. Rate Case Expense

The Company's electric and gas Rate Case Expense shown in the Income Statements set forth in Appendix A incorporate legal and consulting expenses and other miscellaneous expenses associated with filing a rate case. The Signatories agree to a three-year amortization of rate case expense.

5. Productivity Adjustment

The Income Statements set forth in Appendix A incorporate a 1.5% productivity adjustment to the Company's gas and electric expenses in each Rate Year. The productivity adjustment is calculated on a total base including labor, pensions, OPEBs, fringes, and payroll tax expenses.

6. Major Storm Reserve

The electric Income Statements set forth in Appendix A incorporate $700,000 in funding for a Major Storm Reserve for each Rate Year. The Major Storm Reserve procedures and operation are set forth in Appendix Q.

7. Security Costs

The Signatories recognize that the Company requires adequate resources to provide security for its facilities and a safe environment for its customers, employees, contractors and guests. Accordingly, the Income Statements set forth in Appendix A incorporate funding for Security of Infrastructure.

8. Common Cost Allocation

The Signatories agree that the common cost allocation should be modified from the 85% electric and 15% gas allocation authorized in the 2010 Rate Order.

Accordingly, the common cost allocation of 80% electric and 20% gas will be utilized and applied to O&M expense, plant and related property taxes and depreciation.

9. Network Strategy and Distribution Automation

The electric Income Statements set forth in Appendix A reflect revenue requirements related to plant in service in each of the three Rate Years, including Network Strategy and Distribution Automation capital expenditures. However, full implementation of the Network Strategy and Distribution Automation project beyond Rate Year 1 is dependent upon Staff's agreement that the Company remain on track for the successful demonstration of the functional capability and operation/integration of these investments.

The Company will file an initial report ("Initial Report") with the Secretary of the Commission ("Secretary") within 30 days of Commission approval of this JP containing the proposed Network Strategy and Distribution Automation projects' scope and major performance milestones. The milestones will establish a specific time for meeting clear, readily measured indicators showing functional capability and operation/integration. To recognize potential future costs in the event that the Network Strategy and Distribution Automation capital projects are not fully pursued, the Initial Report will also set forth the Company's expected capital expenditures and incremental operating expenses ("Business as Usual Case"). The Business as Usual Case, or expenditures incurred related to it, are not being advanced, addressed, or otherwise supported in this JP given that the Network Strategy and Distribution Automation Capital Projects have been included. Staff and the Company agree to meet to reach mutual agreement on the major performance milestones within 60 days of filing the Initial Report. If mutual agreement cannot be reached, either party may seek a ruling from the Commission regarding appropriate milestones.

The Company will file with the Secretary a major milestone performance report, no more than twice annually, within 15 business days of a milestone completion date ("Milestone Report") which describes the Network Strategy and Distribution Automation project's compliance with the applicable milestone or milestones. In addition to identifying compliance with the specified milestone's indicators, the Company will identify and describe in the Milestone Report its view of the project's direct customer and electric grid 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 the Commission's Reforming the Energy Vision proceeding 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 Managing Director of Utility Rates and Services ("Director") for approval. The Director's approval of the continuation of the project 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 project, the Company is authorized to continue project implementation, including continuation of recovery for all prudently incurred and committed expenditures (for example material purchases and internal and external labor). In the event that the Director or the

Commission delays or cancels deployment and implementation of the Network Strategy and/or Distribution Automation 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 Network Strategy and/or Distribution Automation Project.

It is recognized and acknowledged by the Signatories that the full realization and measurement of many of the benefits associated with the Network Strategy and Distribution Automation project may not be realized in the short term or would continue to appreciate in value over time. This fact will be recognized in the selection of milestones. For example, proper assessment of the value of volt-var optimization requires that measurements be taken over a full year such that seasonable load profiles are considered. The Signatories also recognize that benefits of projects, such as the volt-var project discussed above, will also improve once they can be applied centrally through the Distribution Management System ("DMS"). DMS is not anticipated to be fully functional during Rate Year 1. Other grid functions/capabilities from the projects such as Fault Location, Isolation, and Service Restoration and real time load transfers also require full DMS implementation to maximize available benefits.

10. Energy Efficiency Funds

The electric and gas Income Statements set forth in Appendix A reflect a rate allowance for Energy Efficiency funding. Rate Year 1 funding for Energy Efficiency program expenditures reflects a half year of the continuing EEPS2 surcharge and a half year of base delivery rate funding. Funding for Energy Efficiency in Rate Year 2 and

Rate Year 3 reflects inclusion of a full year of all Central Hudson Energy Efficiency program expenditures in base rates. Savings targets for both gas and electric are maintained at current EEPS2 targets. Nothing in this JP precludes any party from raising positions in the other Commission proceedings regarding the optimal budget, design and/or implementation of Central Hudson's Energy Efficiency programs.

11. Gas Excess Cost of Removal

The Signatories agree that all gas costs of removal, including salvage, will be charged to the depreciation reserve.

IV. RATE YEAR NET PLANT ADDITIONS

A. Net Plant and Net Plant Targets

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 targets set forth in Appendix B. These net plant 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 at the end of each Rate Year will be calculated using the calculation methods described in Appendix C.

3. Reconciliations

The actual electric and gas net plant will be reconciled to the electric and gas net plant 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 C) resulting from the difference (whether positive or negative) in actual average net plant balances and the target levels will carry forward for each of the Rate Years and will be summed algebraically at the end of Rate Year 3. The Company is authorized to defer for future recovery any incremental costs it incurs with respect to implementing a gas unit cost tracker, which requires the Company to collect and maintain information at a higher degree of granularity. The cost is estimated to be $250,000 and recovery will be capped at that amount. The Company and Staff will work together to develop the gas unit cost tracker information which will be reported annually to coincide with the annual Leak Prone Pipe Replacement Report.

4. Deferral For the Benefit of Ratepayers

If at the end of Rate Year 3 the cumulative incremental revenue requirement impact from net plant additions 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 succeeding Commission rate order.

5. Related Reporting

The Company will provide Staff by March 1, 2016, 2017, and 2018 a report on its capital expenditures during the prior calendar year using a format similar to the format set forth in Appendix D of the 2010 Rate Order. This format also is presented in Appendix D to this JP. In addition, the Company will file its five year capital investment plan with the Secretary annually starting on July 1, 2016.

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

V. ACCOUNTING MATTERS

A. 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 expenses and costs as specified in the 2010 Rate Order 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 or policy of general applicability or by reason of a Commission determination with specific reference to the Company.

Without limiting the foregoing, the accounting deferrals applicable in Rate Year 3 from the 2010 Rate Order include the following expenses and costs that will continue without modification:

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

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

c) Interest Costs on Variable Rate Debt;

d) Interest Costs on the cost rate of New Debt Issuances in Rate Year 2 and Rate Year 3;

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

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

g) Enhanced Powerful Opportunities Program (“EPOP”) and Low Income Bill Discount Programs;

h) New York State Assessment and Commission General Assessment;

i) Net Lost Revenues associated with the Merchant Function Charge;

j) Revenue Decoupling Mechanisms (Electric and Gas);

k) Deferred Temporary Metro Transit Bus Tax Surcharge;

l) Deferred Unbilled Gas Revenues;

m) Renewable Portfolio Standards (“RPS”), EEPS and System Benefits Charge (“SBC”);

n) Economic Development Plan Implementation;

o) Competition Education Campaign Program;

p) Commodity-Related Deferrals;

q) NMP2 Costs; and

r) Revenue Requirement of Net-Plant Shortfall.

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

2. Modified Deferrals

The following deferrals from the 2010 Rate Order are modified:

a) All Environmental Site Investigation and Remediation Costs

The Company is authorized to continue to defer all environmental Site Investigation and Remediation ("SIR") Costs as authorized by the Acquisition Order.

b) Deferral of Actual Costs of Debt as Compared to Forecast

In all three Rate Years the actual interest rate of variable rate debt, consisting of the 1999 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 H, Schedule 2 and the difference will be reflected in the updated average cost of long term debt and the updated weighted 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. In addition, for Rate Years 2 and 3 only, the actual interest rate incurred for new fixed rate debt will be reconciled to the interest rates shown in Appendix H, Schedule 2 and the differences will be reflected in the updated average cost of long term debt and the updated weighted cost of debt for the respective Rate Year. At the end of each Rate Year, the total difference between the forecasted weighted cost of long term debt and the actual weighted cost of long term debt for that Rate Year as determined above, will be multiplied by the forecasted rate base amounts as indicated in Appendix A to determine the electric and gas amounts to be deferred for future recovery, or returned to customers, with carrying charges at the PTROR.

c) Property Tax True-Ups and Deferrals

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 return 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 10 basis points per (electric and gas) department for Rate Year 1 and 5 basis points per (electric and gas) department for Rate Year 2 and Rate Year 3.

d) Governmental Actions

The Company is authorized to defer the revenue requirement effect of new legislative, governmental, Commission or other regulatory actions subsequent to the execution hereof that individually have material consequences (10 basis points or more of return on common equity for either the gas department or the electric department) for any elements of cost, with carrying charges at the PTROR.

e) International Financial Reporting Standards ("IFRS")

The Company is authorized to defer its actual non-labor costs of planning for and implementing IFRS incurred during the term of the Rate Plan.

f) Management and Operation Audit Costs

The Company is authorized to defer its actual outside professional or consultant-related costs incurred, in responding to any Commission initiated or required

Management or Operations Audit cost, including in Cases 13-M-0314 and 13-M-0449, with carrying charges at the PTROR, for future recovery from customers.

g) Distribution and Transmission ROW Tree Trimming Costs

Actual distribution ROW tree trimming expenditures will be compared to the sum of the Rate Year expense allowances over the three year term. Any cumulative under-spending at the end of a Rate Year will be deferred for future return to customers with carrying charges at the PTROR.

Actual transmission ROW tree trimming expenditures will be compared to the sum of the Rate Year expense allowances over the three year term. Any cumulative under-spending at the end of a Rate Year will be deferred for future return to customers with carrying charges at the PTROR.

h) Stray Voltage

Actual Stray Voltage testing and mitigation expenditures will be compared to the Rate Year expense allowance. The difference between the rate allowance and actual Stray Voltage testing and mitigation expenditures will be deferred on a two-way basis for either future recovery by the Company, or return to customers, with carrying charges at the PTROR.

3. Expiring Deferrals

The accounting deferrals from the 2010 Rate Order for the following expenses and costs will expire:[14]

a) SBC Gas Low Income Program;

b) Information Technology Expense;

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14 The deferral of $1.85 million of synergy savings from the Acquisition Order will also expire.

c) Transmission Sag Mitigation Costs-Capital Projects;

d) Gas Main Replacement Program;

e) SC 11 Levelized Rate; and

f) FAS 112 Long Term Disability.

4. New Deferrals

The following new deferrals are added:

a) Security Costs

Actual security costs will be compared to the Rate Year allowances on a Rate Year basis. Any under-spending as of the end of a Rate Year will be deferred for future return to customers with carrying charges at the PTROR.

b) Rate Case Expense

Actual Rate Case expense will be recorded against the Rate Case expense allowance as specified in the Appendix A income statements. Any under-spending will be deferred for future return to customers with carrying charges at the PTROR. The Company is authorized to defer the Rate Case expenses related to these cases, subject to the following limits: External Legal Costs at $850,000; Return on Equity Consultant Costs at $60,000.

c) Clean Energy Fund/NYSERDA Surcharge

The Signatories to the JP recognize the uncertainty surrounding the Clean Energy Fund, which as potentially structured may encompass existing items such as RPS, SBC, EEPS and 18-a or other items for which deferral is currently provided. To the extent not otherwise addressed or superseded by the Commission Order in the

Clean Energy Fund proceeding,[15] the Company is authorized to defer the difference in actual expenses incurred in connection with the Clean Energy Fund to the costs collected from customers on a Rate Year basis. The differences between the actual expense and the costs collected from customers will be deferred on a two-way basis for future recovery by the Company, or return to customers, with carrying charges at the PTROR.

Similarly, the Signatories to the JP recognize the uncertainty surrounding Part P of the Governor's proposed budget that includes an additional NYSERDA and Department of Environmental Conservation's climate change program surcharge on gas and electric utilities. To the extent not otherwise addressed or superseded by Commission Order, the Company is authorized to defer the difference in actual expenses incurred in connection with this surcharge to the costs collected from customers on a Rate Year basis. The difference between the actual expense and the costs collected from customers will be deferred on a two-way basis for future recovery by the Company or return to customers, with carrying charges at the PTROR.

d) CHGE Energy Efficiency Portfolio

Any unspent funds will be deferred with carrying charges at the PTROR.

e) Major Storms (Electric Service Only)

Actual Major Storm Costs will be compared to the Major Storm Reserve rate allowance on a Rate Year basis, subject to the provisions in Appendix Q. The differences between the rate allowance ($700,000 per Rate Year) and actual Major

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[15] Case 14-M-0094 - Proceeding on Motion of the Commission to Consider a Clean Energy Fund, Order Commencing Proceeding (May 8, 2014).

Storm Costs will be deferred for future recovery by the Company or will remain in the Major Storm Reserve with carrying charges at the PTROR.

f) REV Demonstration Projects

To the extent not otherwise addressed or superseded by subsequent Commission Orders, the Company is authorized to defer for future recovery the incremental revenue requirement effect, net of revenues of the Company's share of Reforming the Energy Vision ("REV") Demonstration Project capital expenditures up to $10 million including recovery of related operations and maintenance costs associated with any REV Demonstration Project not paid by the project participants or a third party that is authorized by the Commission in these proceedings, with carrying charges at the PTROR. If, upon further development, REV Demonstration Project capital expenditures appear likely to exceed $10 million, and are not paid by the project participants or a third party, the Company may petition the Commission for authorization to defer additional funds. The Company shall file quarterly reports with the Secretary that include all relevant details including: revenue requirement amounts, project details such as descriptions and in-service dates, incremental costs incurred, operational savings, tax benefits, grants, and all Company-identified benefits.

g) Non-Net Income Based Calculation of State Income Taxes

The Company is authorized to defer the incremental state income tax expense for any non-net income based calculation of state income taxes during the term of the Rate Plan. If the Company is required to file state income tax based on a non-net income based calculation, it will file a notice with the Secretary including the calculation of the incremental state income tax and the change that caused the Company to fall into a non-net income based tax calculation. This notice will be in lieu of the filing of a deferral petition and would not be subject to the Commission's traditional three-part deferral test. The method of the recovery of any deferred amounts will be addressed in Central Hudson's next rate case.

h) Bonus Depreciation

If bonus depreciation is extended, the Company is required to defer the revenue requirement impact of the bonus depreciation reduction to rate base during the term of the Rate Plan or until such time as superseding rates are set by the Commission.

i) Unbilled Electric Revenues

The Company will be authorized to defer the difference between total unbilled electric revenue and the amount recovered in revenue.

j) Danskammer Gas Revenues

Actual delivery revenues associated with providing gas service to Danskammer will be deferred for the benefit of customers, with carrying charges at the PTROR.

k) Energy Efficiency Incentives

The Company is authorized to accrue carrying charges on the net of tax deferred Energy Efficiency incentives (EEPS1 and EEPS2) at the PTROR effective July 1, 2015 until the Commission acts upon the deferred incentives earned.

l) Additional Leak Prone Pipe Replacement Deferral

In the event the Company replaces or eliminates Leak Prone Pipe in excess of its mileage target in any calendar year, for each mile in excess of the applicable target, the Company shall receive a positive revenue adjustment of 2 basis points per additional mile, capped at a maximum of 5 miles (10 basis points) per calendar year, which the

Company will defer for future recovery. This deferral would allow for up to $1.4 million for every mile over 13 miles in 2016, up to $1.5 million for every mile over 14 miles in 2017, and up to $1.6 million for every mile above 15 miles in 2018. For the avoidance of doubt, the Company is expressly authorized to include Leak Prone Pipe eliminations (abandonment, disuse or any other method that terminates use of the Leak Prone Pipe while still serving the customer) in this deferral mechanism.

m) Asset Retirement Obligation Depreciation and Accretion Expense

The Company is authorized to defer asset retirement obligation depreciation and accretion expense consistent with the Uniform System of Accounts.

B. <u>Listing of Deferrals</u>

A listing of deferrals is set forth in Appendix E, 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 not been included. 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 XVIII of this JP.

C. <u>Deferral Extension/Continuation</u>

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.

D. <u>Right to Petition</u>

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 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 the Rate Plan, any Signatory hereto may petition the Commission to adjust the Company's rates accordingly.

E. Projected Net Deferred Regulatory Credits

Actual July 1, 2015 balances for the items shown on Appendix F will be offset against each other as of July 1, 2015, with the net deferred credit balance available for rate moderation. Any unused balance shall remain deferred, with carrying charges at the PTROR.

F. Revenue Matched Rate Allowances

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

VI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure

The capital structures and cost rates for debt and other customer capital are shown by Rate Year in Appendix H.

B. Allowed Rate of Return on Common Equity

The allowed return on common equity ("ROE") is 9.0% for all three Rate Years.

C. Earnings Sharing

The allowed ROE established for the term of the JP is 9.0%. Actual regulatory earnings in excess of 9.0% are authorized and those in excess of 9.5% ROE and up to

10.0% ROE will be shared equally between customers and shareholders. Actual regulatory earnings in excess of 10.0% ROE and up to 10.5% ROE will be shared 80/20 (customer/shareholder). Actual regulatory earnings in excess of 10.5% ROE will be shared 90/10 (customer/shareholder). These earnings sharing percentages shall be maintained until the effective date of the succeeding Commission rate order.

VII. ADDITIONAL REPORTING REQUIREMENTS

A. Empower

Empower is a program currently run by NYSERDA that provides no-cost energy efficiency solutions for income-eligible New Yorkers. The Company agrees to contact via e-mail its existing energy efficiency vendors and a list of specific Energy Service Company e-mail contacts provided by Staff regarding vendor interest in providing an alternative service to Empower. To the extent a vendor responds back to the Company expressing interest and capability, the Company will provide Consumer Services Staff with the vendor response and contact information. Staff, UIU, and the Company will meet to discuss the viability of an alternative program to Empower.

B. Low Income Customers

The Company will query via telephone in Rate Year 1 all potentially eligible customers for EPOP that it has identified that have not enrolled in EPOP to determine why such customers have not sought to participate in the program. The Company further agrees to provide information shared by customers on an aggregated basis (to protect customer privacy) to Staff, UIU and other interested parties. The Company will also continue to file quarterly and annual reports and evaluations of its low income programs with the Secretary.

C. Security

The Company will provide an annual report to the Director of Utility Security regarding major security upgrades and projects. In addition, within 60 days of the date of this JP, Central Hudson shall provide the Director of Utility Security with an initial security report. The initial security report shall include a detailed description of the electronic security measures presently in place and functioning at Company-owned 345 kV substations, and the extent to which such security measures are now providing real time imaging and alert information to a Company security monitoring facility. For any 345 kV substation not presently equipped, or not yet fully equipped, with electronic security measures, the Company shall include in the initial report a detailed plan for the deployment of such measures with specific timelines for the targeted completion and activation of them at each substation. The present and anticipated future capabilities of electronic security at the 345 kV substations shall be fully described, to include identification of intrusion detection technology solutions, video surveillance capability and area coverage, and the connectivity/monitoring technology required to ensure these security measures work as a full-time integrated system.

D. Network Strategy and Distribution Automation Project

The Company will file with the Secretary quarterly status reports regarding the Network Strategy and Distribution Automation project expenditures including a brief description of progress toward the next milestone.

E. Reporting of Actual Earnings

The Company will report within 90 days following the end of each Rate Year to the Secretary showing a computation of its achieved regulatory rate of return on common equity for the preceding Rate Year period. The 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 48% or Central Hudson's actual average common equity ratio. The financial consequences of any regulatory incentives positive or negative, and other exclusions consistent with existing practices, will be excluded in the computations of the regulatory rate of return on common equity.

F. Gas Safety

The Company will submit a report to the Deputy Director of the Office of Gas and Water in the Office of Electric, Gas and Water on its performance in the areas of the recommended targets set forth in Sections XIV.E within 60 days following the end of each calendar year.

VIII. 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 I. Billing determinants corresponding to these forecasts are also set forth in Appendix K.

IX. REVENUE ALLOCATION AND RATE DESIGN

A. Revenue Allocation

1. Electric Revenue Allocation

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

2. Gas Revenue Allocation

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

B. Rate Design

1. Electric Rate Design

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

2. Gas Rate Design

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

In addition, the Signatories agree to Staff's volumetric Service Classification ("SC") 11 rate design and acknowledge that the change in SC 11 rate design to a volumetric basis will require conforming structural changes to other charges such as the New York State Assessment (18-a). Any rate moderation will be applied to all classes on a volumetric basis.

3. Customer Bill Impacts

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

X. PROVISIONS FOR LOW INCOME CUSTOMERS

A. Enhanced Powerful Opportunities Program ("EPOP")

The Company is authorized to continue its existing Commission-approved EPOP program, with total EPOP funding as shown on the income statements in Appendix A. In the event the actual costs of the program in any Rate Year vary from the authorized expenditure level, any excess costs incurred by the Company will be deferred for future recovery up to 15% of the total program costs and any under expenditures will be rolled over for program use in subsequent Rate Years with carrying charges at the PTROR.

B. Low Income Bill Discount Program

The Company is authorized to continue its Low Income Bill Discount program for the Home Energy Assistance Program ("HEAP") recipients as modified and approved by the Acquisition Order. The bill discount credits are as follows:

Service Type	Electric Only	Gas Only	Both Electric & Gas
Heating	$17.50	$17.50	$23.00
Non-Heating	$5.50	$5.50	$11.00

The bill discount credits will be applied up to the total corresponding funding in rates, as has been reflected in the Appendix A Income Statements. Any accumulated balances of program under-spending will remain in the Low Income Bill Discount program and carrying charges will be applied at the PTROR. In the event that increases in the numbers of customers qualifying for HEAP occur and the funding for the discounts provided in Appendix A is inadequate to provide the 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.

The Signatories acknowledge that the Commission has initiated a new Low Income Proceeding in Case 14-M-0565 that may modify the Company's low income programs. To the extent the Commission orders modification to the Company's low income programs, the Company will be held harmless from the change in expenses associated with the revised or new low income programs and will be authorized to defer the difference between the rate allowance during each Rate Year and the actual costs for low income programs for future recovery with carrying charges at the PTROR.

C. Weatherization

Staff, UIU and other interested parties will work with NYSERDA's EmPower program (or any successor program) and Homes and Community Renewal's Weatherization Assistance Program ("WAP") to address the waiting list maintained by WAP of Central Hudson gas customers seeking weatherization services. In the event gas delivery revenues materialize from the operation of Danskammer and in the event the Commission determines that EmPower (or any successor program) does not have sufficient funds to provide weatherization services to the gas customers on WAP's waiting list, UIU may petition the Commission for use of the portion of Danskammer gas delivery revenues allocated to residential customers for this purpose.

D. Same-Day Reconnection Program

The Signatories agree that the Company will implement a Same Day Reconnection Program. The Income Statements set forth in Appendix A reflect a rate allowance of $35,000 in each Rate Year for the implementation of the Same Day Reconnection Program. For the avoidance of doubt, the Same Day Reconnection Project will not be funded by shareholders. Given the additional rate allowance, the Company will strive to achieve not less than 80% reconnection within the same day.

The Company shall file a report on residential same-day reconnections for each calendar quarter ("Reporting Period"). Each report should be filed with the Secretary, with copies by e-mail to interested parties, within 30 days after the end of each Reporting Period. The report will indicate the number of residential electric customer reconnections issued by 5:00 PM, Monday through Friday, and the number of same-day reconnections attempts made to such customers.

XI. 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. Reconnection Charges

Whenever service is restored to the same customer at the same meter location within twelve months after discontinuance of service, the Company will make a charge of $20 or in the event an electric line crew is required to perform the service reconnection the charge will be $100; if service is restored during the hours from 8:00 AM to 4:30 PM, on days the main business office of the Company is open for business. If service is restored during other hours the charge will be $40 or $140 if an electric line crew is required to perform the service reconnection. Where a customer receives both electric and gas service, the Reconnection Charge for only one service will apply in the event of the simultaneous reconnection of both gas and electric service.

C. Electric Service Classification No. 8 (Public Street and Highway Lighting)

Rate B, wherein the Company maintains customer-owned fixtures, will be closed to new installations effective July 1, 2015. Rate C, wherein the Company provides delivery service to customer-owned and maintained fixtures, will continue to provide customers with the flexibility to choose any type of facility that will service their needs.

D. Economic Development Funding

This Rate Plan includes no expense allowance for Economic Development, with all program funding being provided from existing economic development fund balances.

Central Hudson shall continue its existing Economic Development programs, including its: Shovel Ready Grants; Wired Building Grants; Job Creation Grants; Revitalization Grants; Business Retention Grants; Regional Marketing Funds; Substation Credits; and the Main Street Revitalization Program.

E. Gas Design Day Forecasting

The Company will submit to Staff the detailed work papers supporting its separate capability forecast for design day and winter season demand requirements which is prepared for the annual winter preparedness review commencing with the 2015-2016 winter review. These work papers will be included in all future rate case filings.

F. Unauthorized Use of Gas

The Company will revise its tariffs to clearly state that charges for unauthorized use of gas and non-compliance are by definition penalty charges.

G. Gas SC 11 Electric Generation Subclass

A new SC 11 subclass, Electric Generation ("SC11EG"), will be established as of July 1, 2015 and will be applicable to electric generation facilities with a minimum generation capacity of 50 megawatts taking firm transportation service from Company facilities at transmission pressures. SC11EG rate design will be based on a Maximum Daily Quantity ("MDQ") structure with the Transportation Rate component of the Monthly Rate reflecting a monthly customer charge of $1,200 and a demand charge of $9.25 per Mcf of MDQ for the term of this JP. All other tariff provisions of SC 11 contained in P.S.C. No. 12 – Gas, as they may be modified or superseded by approval of the Commission, will apply to SC11EG.

H. Gas Balancing

The treatment of gas balancing will continue per the 2010 Rate Order, except that the Signatories agree that the current balancing charges for under deliveries applicable to electric generators are not sufficient. All generator customers must be daily balanced. Effective July 1, 2015, the penalty for under delivery during non-operational flow order ("OFO") events will be $2.50 per Ccf in addition to a market based commodity charge per unit. Effective July 1, 2015, the penalty for under delivery during OFO events will be the greater of $5.00 per Ccf plus a market based commodity charge or the price per Dekatherm equal to three times the midpoint of the range of prices reported for the applicable pipeline, as published in Gas Daily, converted to a Ccf basis for billing. Additionally, the default position for all new customers (i.e., new gas loads as opposed to existing gas loads that may change ownership) served under SC 11 will be daily balanced, requiring an affirmative response for the monthly balancing option. The Company reserves the right to apply daily balancing on a new SC 11 customer if monthly balancing will negatively impact its ability to maintain gas distribution system reliability.

I. Remote Operated Valves ("ROV") for Electric Generators

ROVs will be required for existing generators if they fail to comply with tariff provisions. All new generators are required from the start of operation to have ROVs provided and installed at the generator's cost. The Company agrees to amend its SC 14 (Interruptible Transportation to Electric Generation) and SC 11 (Firm Transport) tariff language as follows: "To maintain system reliability, the Company may require the installation of a remote operated valve on the service lateral that supplies the Customer at the Customer's cost. Any Customer that fails to comply with a Company issued interruption will be required to have a remote operated valve installed and to pay for all associated charges. Customers applying for transportation service to serve new electric generation facilities will be responsible for paying all charges associated with the installation of this equipment."

J. Continuation of ECAM, GSC and PPA Allocation

The existing ECAM and GSC mechanisms, including the allocation of Purchased Power Adjustment costs/benefits, will continue per the 2010 Rate Order.

K. Gas Retail Access Operating Procedures

1. Cash-Out

A revised cash-out process for the Retail Access program will be implemented, no earlier than April 2016, to cash-out, in any given month, those accounts with valid meter readings during the month. Cost recovery will be provided for all incremental external costs Central Hudson incurs to implement this "semi-monthly" cash-out process.

2. Winter Bundled Service ("WBS") Pricing

The commodity component of the WBS price will be revised each month to reflect the Company's actual weighted average cost of storage ("WACOS") for the preceding month. The methods utilized to determine the non-commodity components of the WBS price will remain unchanged. The resulting WBS price will be made available on the Company's website. Due to timing differences between the availability of pricing data and filing requirements, the WBS price and the WACOS will be included on the Company's Statement of Firm Transportation Rates on a one month lag.

3. Collaborative Opportunity

Upon expression of written interest from three or more members of the retail access community, the Company will initiate a collaborative for the purpose of discussing and addressing any specific operations or other concerns.

L. <u>Gas Expansion Program</u>

1. Customer Conversion Assistance Program

A $1.0 million annual program for each Rate Year will be jointly designed by Staff and the Company to provide additional incentives and support for customer conversion to gas. Funding for the program will be provided from available rate moderators. Unused funds shall be available for general rate moderation purposes at the conclusion of this JP.

2. Capacity Requirements

The Company will continue to provide the Secretary with confidential reporting regarding the amount of winter capacity reserve as part of the Company's annual Winter Review.

3. Gas Expansion Performance Incentive

The Company is authorized to receive an annual incentive in the form of 1 basis point for every 200 gas customers added above the combined total customer count forecasted for Residential and Commercial customers for each of the Rate Years. The Company will provide a report to the Secretary identifying its annual customer growth by service class within 45 days of the completion of the Rate Year.

M. Electric RDM

The electric revenue decoupling mechanism (“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 either SC 1, 2, or 6. The RDM is not applicable to SCs 3, 5, 8, 9 and 13.

1. Structure

The structure and provisions of the electric RDM will continue per the 2010 Rate Order except that the provisions for annual and interim RDM periods will be replaced with a provision for semi-annual RDM periods and the provision for the RDM adjustment period will be revised accordingly.

2. Semi-Annual RDM Periods

Semi-Annual RDM Periods are defined as the six months ending December 31 and June 30 and each succeeding six-month period thereafter.

3. RDM Adjustment Period

The RDM Adjustment Period is defined as the six months beginning February 1 or the six months beginning August 1 immediately following each Semi-Annual RDM Period.

4. Delivery Revenue Targets

Delivery Revenue Targets by month for each service classification or sub classification will be based on delivery revenue targets for each Rate Year as set forth in Appendix M.

5. Determination of RDM Adjustment

At the end of a Semi-Annual RDM Period, total delivery revenue excess/shortfalls and associated interest for each applicable service classification or sub classification will be refunded/surcharged to customers through service classification or sub classification-specific RDM Adjustments applicable during a corresponding RDM Adjustment Period. Following each RDM Adjustment Period, any difference between amounts required to be charged or credited to customers in each service classification or sub classification and amounts actually charged or credited will be charged or credited to customers in that service classification or sub classification, with interest, over a subsequent RDM Adjustment period, or as determined by the Commission if no RDM is in effect.

6. Continuation

Delivery Revenue Targets for the Rate Year ending June 30, 2018 shall remain in effect until otherwise changed by the Commission.

N. <u>Gas RDM</u>

The gas RDM will continue to be applicable to SCs 1, 2, 6, 12 and 13. The RDM is not applicable to SCs 8, 9,11,14,15 and 16.

1. Structure

The structure and provisions of the gas RDM will continue per the 2010 Rate Order except that the structure will be revised from a unit per customer model to a revenue per customer model; the provisions for annual and interim RDM periods will be replaced with a provision for semi-annual RDM periods; and the provision for the RDM adjustment period will be revised accordingly.

2. Revenue per Customer

Revenue per customer ("RPC") Targets set forth in Appendix M are determined for SCs 1 and 12 combined and SCs 2, 6 and 13 combined for each month by dividing base revenue, excluding merchant function charge revenue, by customer months based on the revenue and customer forecasts as set forth in Appendix I. Actual RPC will be calculated in the same manner as the target RPC, on a monthly basis, based on actual billed revenue as adjusted by the Weather Normalization Adjustment described in General Information Section 27 of the Company's Gas Tariff and billed customer months. On a monthly basis, any delivery revenue excess or shortfall will be determined as the difference between the actual RPC and the target RPC multiplied by the actual number of customer months billed.

3. Semi-Annual RDM Periods

Semi-Annual RDM Periods are defined as the six months ending December 31 and June 30 and each succeeding six-month period thereafter.

4. RDM Adjustment Period

RDM Adjustment Periods are defined as the six months beginning February 1 or the six months beginning August 1 immediately following each Semi-Annual RDM Period.

5. Determination of RDM Adjustment

At the end of a Semi-Annual RDM Period, total delivery revenue excess/shortfalls and associated interest for each applicable service classification group will be refunded/surcharged to customers through service classification group-specific RDM Adjustments applicable during a corresponding RDM Adjustment Period.

Following each RDM Adjustment Period, any difference between amounts required to be refunded or surcharged to customers in each service classification group and amounts actually refunded or surcharged will be refunded or surcharged to customers in that service classification group, with interest, over a subsequent RDM Adjustment period, or as determined by the Commission if no RDM is in effect. An example of the reconciliation methodology is found in Appendix M, Sheet 9.

6. Continuation

RPC Targets for the Rate Year ending June 30, 2018 shall remain in effect until otherwise changed by the Commission.

O. Conforming Tariffs

The electric and gas tariffs will be amended, as necessary, to conform to the provisions set forth in this JP.

XII. RATE UNBUNDLING AND RETAIL ACCESS LOST REVENUE RECOVERY

The revised methodology approved by the Commission in the 2010 Rate Order which restructured both Merchant Function Charges ("MFC") applied by the Company will continue. Additionally, the existing retail access migration-related lost revenue mechanism will continue per the 2010 Rate Order 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 paid by all customers. Further, electric MFC revenue will continue to be reconciled through the RDM per the 2010 Rate Order.

The current gas MFC Net Lost Revenue mechanism will be replaced with a new gas MFC revenue reconciliation process wherein monthly actual billed MFC revenue, by

MFC group, will be compared to the monthly MFC revenue targets for each rate year as set forth in Appendix M, 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 twelve 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, 2018 shall remain in effect until otherwise changed by the Commission.

A. <u>Lost and Unaccounted For Gas ("LAUF") and Factors of Adjustment ("FOA")</u>

The Signatories agree to the following with respect to LAUF and FOA:

LAUF	
Target FOA (to be updated annually)	1.0044
Top Dead band	1.0182
Bottom Dead band	1.0000

The FOA will be updated annually and will be calculated by averaging the previous five years, ending August 31. The FOA shall be in accordance with Staff's White Paper on LAUF Gas. Line pack and conversion values will be excluded from the calculations. Annual negative values when calculating the five-year average target FOA will be set to zero. The dead band will remain fixed until modified by the Commission.

The electric service level FOA will be set based on the most recent 36 month system average and the methodology per the 2010 Rate Order.

B. Interruptible Imputation

The interruptible imputation structure as set forth in the 2010 Rate Order will be continued and the imputation will be set at $3.0 million for each Rate Year.

XIII. REFORMING THE ENERGY VISION

A REV Working Group was formed as part of this JP to present REV demonstration projects for the Commission's consideration at its June 2015 session. An open, transparent stakeholder collaborative process was initiated on January 7, 2015 to further consider and develop the Company's four REV conceptual programs and any additional REV demonstration projects identified by the REV Working Group. The Company will file a report no later than May 1, 2015 further detailing the REV demonstration projects developed by the collaborative for Commission consideration. The report will provide details on the demonstration projects, including project descriptions, milestones, costs and how those costs would be recovered. The report will identify how the demonstration projects meet the criteria summarized by the Commission in its December 12, 2014 Memorandum and Resolution on Demonstration Projects in Case 14-M-0101 or criteria otherwise adopted by the Commission in Case 14-M-0101. Parties may file comments on the report no later than May 15, 2015. To the extent collaborative members disagree with portions of the report filed by Central Hudson, the fact that the Company – as opposed to a different party – is filing the report does not bestow any preference or priority on its positions vis-à-vis the positions of other parties. Nothing in this JP precludes a party from seeking authorization to respond to any comments that may be filed in response to the report on May 15, 2015.

Individual collaborative members are free to support or object to any project or aspect thereof described in the May 1, 2015 Company report. All collaborative members, however, agree to support or not oppose cost recovery for all of the REV demonstration projects ultimately approved by the Commission.

The REV Working Group may continue to meet as necessary following the resolution of the above-captioned cases to develop future waves of REV demonstration projects and to monitor the progress of demonstration projects approved by the Commission.

The Signatories acknowledge that the Commission has initiated Case 14-M-0101, the determinations from which will take precedence and may require the implementation of certain REV opportunities, procedures, or requirements impacting or effecting Central Hudson and its customers while the terms of this JP are operative. If such implementation of REV opportunities or requirements were to occur, the Signatories agree that Central Hudson may petition to defer any incremental associated costs it incurs and that such a petition will be exempt from compliance with the Commission's traditional three part test for deferral.

XIV. PERFORMANCE MECHANISMS

A. Customer Service

The Customer Service Quality Performance Mechanism and associated reporting requirements will continue per the Acquisition Order and will consist of the following measures: PSC Annual Complaint Rate, the Customer Satisfaction Index, and Appointments Kept measures. All Customer Service Quality Performance Mechanism targets and potential Negative Revenue Adjustments ("NRAs") shall remain in effect until modified by a Commission order.

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

PSC Annual Complaint Rate	**NRA**
<1.1	None
1.1	$950,000
1.2	$1,140,000
1.3	$1,330,000
1.4	$1,520,000
1.5	$1,710,000
1.6 or higher	$1,900,000
Total Amount at Risk	**$1,900,000**

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

CSI Satisfaction Index	**NRA**
85% or higher	None
84% ≤ CSI < 85%	$475,000
83% ≤ CSI < 84%	$950,000
82% ≤ CSI < 83%	$1,425,000
< 82%	$1,900,000
Total Amount at Risk	**$1,900,000**

The NRAs for the Customer Service Quality Performance Mechanism will be multiplied by 1.5 if targets are missed during a dividend restriction period.

B. Appointments Kept

The Company will credit customers $20 per missed appointment.

C. <u>Service Termination Reductions</u>

The Company and the Signatories desire to reduce service terminations to residential customers. Accordingly, an annual incentive for the Company is authorized in the form of a 5 basis point Positive Revenue Adjustment ("PRA") for each Rate Year in which it has reduced service terminations to residential customers in occupied buildings below 11,000 terminations. The Company will provide a report to the Secretary identifying its efforts to reduce terminations and whether it achieved the positive incentive for that Rate Year within 45 days of the completion of the Rate Year.

D. <u>Electric Reliability</u>

The electric service annual metrics for System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") will be set at targets of 1.30 and 2.50, respectively, and shall continue at these levels throughout the term of the Rate Plan. Electric Reliability Reporting requirements, quarterly meeting requirements, revenue adjustment source, and exclusions are defined in Appendix P. If the Company fails to achieve an annual SAIFI target of 1.30 it will be subject to a 30 basis point (electric, pre-tax) potential NRA. If the Company fails to achieve an annual CAIDI target of 2.50 it will be subject to a 30 basis point (electric, pre-tax) potential NRA.

The NRAs for the Electric Reliability Metrics will be multiplied by 1.5 if targets are missed during a dividend restriction period.

All electric reliability targets shall remain in effect until modified by a Commission order in a subsequent Central Hudson electric rate case.

E. Gas Safety

The Signatories agree to the following Gas Safety Metrics. Emergency response performance and damage performance shall adhere to the reporting criteria for the annual Gas Safety Performance Measures report.

1. Emergency Response Time

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

Emergency Response Time	**Percent Completed**	**NRA (BP)**
30 Minute Response	75%	8
45 Minute Response	90%	4
60 Minute Response	95%	1

2. Gas Leak Backlog

The Gas Income Statements set forth in Appendix A include rate allowances for the Company's forecast of the number of gas leaks to be repaired and the costs per average repair. The backlog targets per the following table are actionable on a calendar year basis. In the event the Company incurs more costs than provided for in rates, the Company is free to seek deferral for any excess amount expended above the corresponding rate allowances that are based upon a fixed number of leaks assumed to be repaired and the cost per average leak. Should the Company fail to achieve the Gas Leak Backlog targets in any Calendar Year starting in 2015, it will be subject to the basis point ("BP") (gas, pre-tax) potential NRAs listed below.

Gas Leak Backlog	**# of Leaks**	**NRA (BP)**
Total Year-End Backlog	200	12
Repairable Leaks Backlog	16	16

The Signatories agree that the Damage Prevention targets listed above were established with the intent of moving Central Hudson closer to the statewide averages for such targets. The Signatories further agree that the Company's Damage Prevention targets should therefore at no point during the agreement be more stringent than the statewide averages. Accordingly, the Damage Prevention targets listed above will be reevaluated annually following the issuance of Staff's annual Gas Safety Performance Measures Report. Should the statewide Damage Prevention target averages, as reported in Staff's annual Gas Safety Performance Measures Report, increase above the targets set forth herein, Central Hudson's may petition for adjustment of the Damage Prevention targets for the calendar year in which the report was issued. The targets in place for 2018 shall remain in place until changed by the Commission.

3. Gas Total Damage Targets, Mismark Targets, and Company/Company Contractor Damages

The gas Total Damage targets, Mismark targets, and Company/Company Contractor Damages ("CCCD") and corresponding potential NRAs are as follows:

Gas	**Calendar Year End (per 1000 tickets)**			**NRA (BP)**
	2016	**2017**	**2018**	
Total Damages	2.2	2.05	1.90	4
Mismarks	0.45	0.40	0.36	8
CCCD	0.25	0.20	0.10	8

4. 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 N 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 100 basis points on a calendar year basis, as follows:

High Risk Violation	Occurrences	BPs Per Occurrence
Per Calendar Year	1-25	1/2
	26+	1

Low Risk Violation	Occurrences	BPs Per Occurrence
Per Calendar Year	1-25	1/9
	26+	1/3

This metric will be measured on a calendar year basis. At the conclusion of each audit, Staff will offer and hold a compliance meeting with Central Hudson where Staff will present its findings to Central Hudson. Central Hudson will have five business days from the date the audit findings are presented to cure any identified document deficiency. Only official Central Hudson records, as defined in Central Hudson's Operating and Maintenance plan, will be considered by Staff as a cure to a document deficiency. Staff will submit its final audit report to the Secretary. If Central Hudson disputes any of Staff's final audit results, Central Hudson may appeal Staff's finding[s] to the Commission. Central Hudson will not incur a NRA on the contested finding until such time as the Commission has issued a final decision on the contested findings. Central Hudson does not waive its right to seek an appeal of any Commission determination regarding a violation under applicable law.

If an alleged high risk or other risk violation set forth in Appendix N is the subject of a separate penalty proceeding by the Commission under Public Service Law Section 25 or 25-a, that instance will not constitute an occurrence under this performance metric.

5. Negative Revenue Adjustments

The NRAs for the Gas Safety Performance Mechanisms identified above will be tripled if targets are missed during a dividend restriction period established under the Acquisition Order. The Signatories also acknowledge that the NRAs set forth above in this Section E on Gas Safety have already been doubled as a result of the Acquisition Order. Accordingly, the calculation of any triple NRA would be 1.50 times the basis points shown above.

6. Continuation

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

7. Infrastructure Enhancement for Leak Prone Pipe

The Company agrees to capital expenditures for the replacement or elimination of Leak Prone Pipe at a cost of $1.4 million per mile for 2016; $1.5 million per mile for 2017; and $1.6 million per mile for 2018. The Company further agrees to the following targets for the replacement or elimination of Leak Prone Pipe: a) 13 miles for 2016; b) 14 miles for 2017; and c) 15 miles for 2018. The Company shall maintain the 2018 pipe target until such time as it is changed by the Commission.

In addition, the Company and Staff will work jointly to explore development of an internal, and contractor, workforce development program. A report describing these efforts will be filed with the Secretary within 6 months of a Commission order in this proceeding.

In the event the Company fails to meet its Leak Prone Pipe target in any calendar year, the Company will be subject to an 8 basis point NRA in the immediately following Rate Year. In the event that the Company exceeds the pipe replacement/elimination target in any calendar year, the deferral and incentive provisions set forth above in Section V.A.4.L shall apply in the immediately following Rate Year.

The Company will develop a Leak Prone Pipe replacement/elimination prioritization list such that the risk prioritization model will be used in its development but the Company will have flexibility in ultimately determining pipe replacement/elimination project selection. For the avoidance of doubt, not all sections of pipe to be replaced or eliminated will be selected by the Company based on strict adherence to the risk prioritization model, but the decision and rationale to not follow strict adherence to the model will be documented for each segment and provided to Staff if requested.

XV. OUTREACH & 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 2010 Rate Order.

XVI. MONTHLY BILLING

The Company will transition to monthly billing for all customers from its current bi-monthly billing of certain customer classes by July 2016. The costs associated with monthly billing are set forth in the Income Statements for each Rate Year set forth in Appendix A.

XVII. CLIMATE CHANGE

Central Hudson agrees to review the climate change study produced by the Center for Climate Systems Research of Columbia University for Consolidated Edison Company of New York upon its completion, and any other materials on climate projects furnished to Central Hudson by the Sabin Center. Central Hudson will evaluate whether the results of the study and other materials suggest a need for an adjustment associated with its capital expenditure planning or investment or operational procedures and whether further study may be required. If, after consultation with the Sabin Center, Central Hudson determines that incremental capital investment is necessary as a result of the study, it will discuss the need for such investment with interested Signatories to this JP.

XVIII. ADDITIONAL PROVISIONS

A. Submission and Support

The Signatories agree to submit this JP to the Commission and recommend that it be adopted and approved by the Commission without modification as the resolution of these cases. The Signatories hereto believe that the JP will satisfy the requirements of Public Service Law Sections 65(1) and 79(1) that the Company provide safe and adequate service at just and reasonable rates.

B. Acceptance by the Commission

The Signatories intend this JP to be a complete resolution of all the issues in Cases 14-E-0318 and 14-G-0319.[16] It is understood that each provision of this JP is in consideration and in support of all the other provisions and each provision is expressly

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[16] Signatories have agreed to a process to address unresolved REV demonstration project issues in Section XIII.

conditioned upon acceptance by the Commission of this JP in its entirety without change. If the Commission does not approve this JP according to its terms without change, then the parties to the JP will be free to pursue their respective positions in these cases and any remedies at law or in equity without prejudice.

C. Non-Precedential Nature

The JP is a product of compromise and negotiation among the Signatories. The terms and conditions of the JP apply solely to, and are binding on each Signatory only in the context of, the purposes and results of this JP. None of the terms and provisions of this JP, nor any methodology or principle utilized herein, and none of the positions taken herein by any Signatory may be referred to, cited or relied upon by any other Signatory in any fashion as binding precedent including in any other proceedings before the Commission, any other regulatory agency, or before any court of law for any purpose except in furtherance of the purposes and results of the JP 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.

D. Mutual Cooperation

The Signatories recognize that certain provisions of this JP require that actions be taken in the future to effectuate fully this JP. Accordingly, the Signatories agree to cooperate with each other in good faith in taking such actions. The Signatories specifically acknowledge that the listing of deferrals set forth in Appendix E was intended to be comprehensive and include all existing deferral accounting employed by the Company. Accordingly, Appendix E may be updated by the Company, with consent of Staff, to incorporate any inadvertently omitted deferral via a letter from the Company to the Secretary identifying the omission, thus amending Appendix E.

E. <u>Procedures in the Event of a Disagreement</u>

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 Signatories, 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 Signatories within 15 business days from notification to a Signatory or a longer period if agreed to by the Signatories, any Signatory may petition the Commission for a determination on the disputed matter.

F. <u>Other Permitted Filings</u>

Notwithstanding the other provisions of this JP, the Signatories agree that the following rate changes will be permitted during the effectiveness of this JP, provided that the Commission's approval is granted prior to the implementation of such changes. A minor change is any individual base rate or rates whose revenue effect is *de minimis* or essentially offset by associated changes in other base rates, terms or conditions of service – for example, an increase in a specific base rate charge in the same or in other SCs that is offset by a reduction in a different base rate charge applicable to the same customers or SCs experiencing the increase. The Signatories agree that any Signatory will be allowed to take any position it may wish regarding any such proposed rate change.

It is understood that, over time, such minor changes are routinely made and that they may continue to be made during the effectiveness of this JP provided they will not result in a change (other than a *de minimis* change) in the revenues that Central Hudson's base rates are designed to produce overall before such changes. The Signatories agree that any Signatory will be allowed to take any position it may wish regarding any such proposed rate change.

Notwithstanding the foregoing, while the Company has no intention of changing rates during the effectiveness of this JP, it will make changes if so directed by the Commission.

If a circumstance were to occur that, in the judgment of the Commission, so threatens the Company's economic viability or ability to maintain safe and adequate service as to warrant an exception to this undertaking, then Central Hudson will be permitted to file for an increase in base rates at any time.

The Signatories recognize that the Commission possesses the authority to act on the level of the Company's base 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 JP so as to render Central Hudson's rates unreasonable or insufficient for the provision of safe and adequate service at just and reasonable rates.

Nothing herein shall preclude Central Hudson from petitioning the Commission for approval of new services or the implementation of new SCs and/or cancellation of existing SCs and rate design or revenue allocation changes associated therewith.

G. Trade Secret Protection

Nothing in this JP prevents the Company from seeking trade secret, personal privacy or critical system infrastructure 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 the terms of this JP or to seek confidential treatment of material for any other lawful reason, or prohibits or restricts any other party from challenging any such request.

H. Execution in Counterparts

This JP may be executed in two or more counterparts, each of which together shall be deemed an original, but all of which together shall constitute one and the same instrument. 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.

WHEREFORE, this JP has been agreed to as of the 6th day of February, 2015, 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).

M. L. Mosher

Michael L. Mosher
VP – Regulatory Affairs
Central Hudson Gas & Electric
Corporation

WHEREFORE, this JP has been agreed to as of the 6th day of February, 2015, 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
Staff of the New York State Department
of Public Service
Office of General Counsel

WHEREFORE, this JP has been agreed to as of the 6th day of February, 2015, 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, Esq.
Couch White, LLP
Counsel for Multiple Intervenors

WHEREFORE, this JP has been agreed to as of the 6th day of February, 2015, 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).

Lisa K. Perfetto, Esq.
Earthjustice
Counsel for Pace Energy and Climate Center

NOTE: Party to 14-E-0318 Only

WHEREFORE, this JP has been agreed to as of the 6th day of February, 2015, 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).

Usher Fogel

Dated: February 6, 2015

Usher Fogel, Esq.
Retail Energy Supply Association

WHEREFORE, this JP has been agreed to as of the 6th day of February, 2015, 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).

Christopher Forstrom

Student Worker, Columbia Environmental Law Clinic

Representing the Sabin Center for Climate Change Law

APPENDICES

See separate attachment.