STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 09-E-0588 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service.

CASE 09-G-0589 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.

ORDER ESTABLISHING RATE PLAN

(Issued and Effective June 18, 2010)

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At a session of the Public Service Commission held in the City of Albany on June 17, 2010

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
Robert E. Curry, Jr.
James L. Larocca

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BY THE COMMISSION:

This order adopts terms set forth in a joint proposal submitted for our review by Central Hudson Gas & Electric Corporation (Central Hudson); staff of the Department of Public Service (Staff); and Multiple Intervenors, an association of about 50 large utility customers. We thereby establish a rate plan and other provisions governing the company's electric and gas delivery services, intended to take effect July 1, 2010 and to continue for at least three years.

INTRODUCTION

Background and Procedural History

Central Hudson serves about 301,000 electric customers and 74,000 natural gas customers, 85% of them residential, in eight counties in the mid-Hudson region. We initiated this case to consider rates the company filed on July 31, 2009, which were calculated to increase its annual base revenues by $15.2 million for electric delivery service and $4.0 million for gas delivery service over a rate year starting July 1, 2010. The company's proposal would have resulted in delivery rate increases of 6% for electricity and, likewise, 6% for gas; or, based on energy commodity costs forecasted at that time, it would have increased the typical monthly residential bill for combined delivery and commodity service by $3.46 (3.7%) for electricity and $3.97 (3.5%) for gas.[1] We have suspended the proposed rates through June 27, 2010 while we review the application.[2]

The main justifications asserted in Central Hudson's filing were (in declining order of magnitude) "mandated and externally imposed costs," about 75% of which are local property taxes; reductions in sales volumes, due to weak economic conditions and increased focus on energy efficiency;

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[1] We authorized Central Hudson's last previous general rate increase by setting rates for a single rate year in Cases 08-E-0887 and 08-G-0888, *Central Hudson Gas & Elec. Corp. - Rates,* Order Adopting Recommended Decision With Modifications (issued and effective June 22, 2009)(the 2009 rate order). That decision occurred near the end of the company's three-year rate plan established in Cases 05-E-0934 and 05-G-0935, *Central Hudson Gas & Elec. Corp. - Rates,* Order Establishing Rate Plan (issued and effective July 24, 2006)(the 2006 rate order).

[2] Cases 09-E-0588 and 09-E-0589, Further Suspension of Major Rate Change (issued and effective December 2, 2009); Confirming Order (issued and effective September 17, 2009); Order Suspending Major Rate Filings (issued and effective August 25, 2009).

environmental remediation at the former manufactured gas plant site in Newburgh; the cost of investment capital needed to serve new customers and maintain or upgrade delivery systems for existing customers; and inflationary increases in operating and maintenance expense and labor costs.[3]

On November 17, 2009, after Staff, Multiple Intervenors, and the N.Y.S. Consumer Protection Board (CPB) had reviewed Central Hudson's application and testimony and conducted additional discovery,[4] Staff and the CPB filed their own testimony and exhibits. Staff's filing presented its determination that, in the rate year, continuation of the company's present rates without any increase would generate revenues exceeding the company's revenue requirement by $0.017 million (less than 1%) for electric delivery service and $0.8 million (1%) for gas delivery service. The CPB's testimony advocated a lower allowed rate of return for Central Hudson's investors than the company requested, and modifications in the company's programs for low-income customers.

Central Hudson filed rebuttal testimony December 23, 2009; and it provided subsequent updates for known changes through November 2009, of the type that we ordinarily would recognize after verifying them toward the end of a rate case. (Property taxes were updated as of January 2010.) Staff and the other parties had an opportunity to examine these updates through the discovery process. Upon confirming their accuracy,

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[3] The revenue increases that would be allowed under the Joint Proposal's terms would be attributable to a different combination of "drivers," as described below ("Compliance with the Public Interest") and in Attachment 1.

[4] The Administrative Law Judge was asked to resolve a series of discovery disputes. Cases 09-E-0588 and 09-G-0589, Procedural Rulings (issued November 9, October 26, and October 21, 2009).

Staff calculated that, if Central Hudson submitted them to us as part of an updated application, the company would be seeking increases of $26.3 million (10.3%) for electric delivery service and $7.8 million (11.9%) for gas delivery service (as compared with the original requests of $15.2 million and $4.0 million respectively) for the single rate year starting July 1, 2010.

Meanwhile, the parties' testimony had become a basis for settlement discussions starting November 24, 2009, pursuant to public notice in conformance with 16 NYCRR 3.9. As is customary in such proceedings, the negotiations were open to any party willing to preserve the confidentiality of the discussions in accordance with our regulations. The negotiations culminated in submittal of the Joint Proposal by the company, Staff, and Multiple Intervenors on February 3, 2010.

Instead of addressing only the single rate year presented in the company’s initial filing and updates, the Joint Proposal offers terms that, if adopted, would prescribe rates and other provisions for three successive rate years July 1, 2010 through June 30, 2013. The rate plan calls for electric delivery rate increases of $11.8 million (4.6%), $9.3 million (3.5%), and $9.1 million (3.3%) in Rate Years 1, 2, and 3, respectively. The gas delivery rate increases for Rate Years 1, 2, and 3 would be $5.7 million (8.9%), $2.3 million (3.4%), and $1.6 million (2.3%).

The Joint Proposal’s three sponsoring parties each filed a supporting statement on February 12, 2010. On the same date, the CPB submitted a statement that the proposed residential rate increases precluded it from supporting the Joint Proposal as a whole, but that it endorsed the Joint Proposal’s increases in funds allocated to programs to assist low-income customers. No party filed a statement opposing the Joint Proposal. At an evidentiary hearing on March 9, 2010, the

Joint Proposal and the parties' previously filed testimony, exhibits, and statements were incorporated into the record and were made available, with sponsoring witnesses, for examination by the parties and the Judge. The filed materials and the hearing transcript also have been posted on the Department of Public Service (DPS) website (www.dps.state.ny.us) to afford the public maximum opportunities to review the parties' negotiated proposals.

The procedural milestones established by the Administrative Law Judge included post-hearing briefs in the event that the hearing revealed issues requiring written argument; and in fact, as detailed in a separate section below, testimony at the hearing prompted four rounds of briefs or adversarial pleadings and other motion practice regarding low-income programs. Still another phase of post-hearing argument was prompted by the Judge's ruling, also described separately below, inviting all interested parties to address whether and how the Joint Proposal's schedule of annual revenue increases should be modified so as to "levelize" them, *i.e.*, set each year's increase equal to the previous year's increase instead of allowing them to vary in magnitude from one year to the next during the three-year rate plan. Two rounds of adversarial comments were filed on this issue.

Public Participation

Public statement hearings were held to receive statements on the company's initial filing; and, at the request of local elected officials, additional public statement hearings were held after the Joint Proposal was filed.[5] Each hearing was preceded by notices posted on the DPS website and mailed to

[5] At Kingston, on January 26, 2010 (evening, three speakers) and March 11, 2010 (afternoon, eight speakers), and

elected officials and public libraries; press releases; and large notices published three times before each hearing in each of two newspapers of general circulation in the Central Hudson service territory. Speakers at the hearings numbered 22 individuals who made 25 statements on the record, while several attended without making statements.

The published notices not only invited the public to speak at the hearings but also explained how to comment by mail, e-mail, or telephone. As a result, individual customers have submitted 63 written comments[6] and 114 comments by telephone message on our Opinion Line. In addition, we have received letters, comments, or formal resolutions from elected officials and local governments as follows:

- John J. Bonacic, State Senator;
- Steven M. Saland, State Senator;
- Kevin A. Cahill, State Assembly Member, and Chair, Assembly Committee on Energy;
- Frank K. Skartados, State Assembly Member;
- Daniel P. McCoy, Chairman, Albany County Legislature;

Poughkeepsie, January 26 (afternoon, eight speakers) and March 11 (evening, six speakers), before Administrative Law Judge Rafael A. Epstein and, on January 26 in Poughkeepsie, Commissioner Robert E. Curry, Jr.

[6] In addition, we have received an organized mailing of 41 letters which advocate that Central Hudson modify its tariffs to allow customers to designate their own anniversary date for net metering purposes. According to the letters, this would eliminate a disincentive to customers' installation of solar generation. We will not address the question as part of this case, because there has been no testimony on the subject and, on the other hand, our staff is reviewing such issues on a statewide basis to determine whether tariff modifications are needed for regulated electric utilities generically. The letters submitted in this case will be considered as part of that review.

- Joel Tyner, Dutchess County Legislator;
- Gwen C. Johnson, Member, Common Council, City of Poughkeepsie;
- Andrea Smallwood, Mayor, Village of Athens;
- Carl Chipman, Supervisor, Town of Rochester;
- Andi Turco-Levin, Alderman, Common Council, City of Kingston;
- Bruce McLean, Kingston Local Development Corporation;
- Dutchess County Legislature;
- City of Newburgh, City Council;
- Town of Poughkeepsie, Town Board; and
- Town of LaGrange, Town Board.[7]

One customer, at two public statement hearings, spoke in support of the company’s performance and the proposed rate increases. In addition, some customers expressed appreciation for the company’s efforts to restore service during the prolonged outages resulting from the February snowstorm, although others were dissatisfied with the company’s performance at that time. Otherwise, all the comments oppose any rate increase at all, regardless of the amount; or else they oppose the specific rate increase amount at issue, pursuant to either the original rate application or the Joint Proposal.[8]

The point most frequently raised in the comments is that a rate increase would create hardships for customers, directly through bill increases; and indirectly by making it more difficult to do business or find employment in the

[7] The Dutchess County Legislature and the Towns of Poughkeepsie and LaGrange each filed two resolutions, one opposing the original rate application and another opposing the Joint Proposal.

[8] The hearing transcripts, and all written comments received, can be viewed on the DPS website.

communities where Central Hudson operates. Commenters said the recent history of Central Hudson rate increases contributes to customers' sense of frustration, compounded by their inability to pass their cost increases along to others as the company can. Some customers particularly object to the company's recovery of uncollectibles expense through rates, observing that rate increases tend to increase uncollectibles; a rate allowance for gas manufacturing site remediation, a task not imposed by the current generation of customers; the company's alleged failure to economize in its own operations, as customers must; allowed earnings on shareholders' common equity exceeding the returns available to non-shareholders, such as interest rates on bank deposits; and management salaries as described in news reports.

On a broader scale, customers say they are concerned not only that utility rates affect individuals directly but also that they burden local governments, businesses, farms, and property owners, and constitute a hidden cost of goods and services produced through the use of energy. Customers cite this as a factor that exacerbates the decline of the local economy, forcing curtailment of government services and deterring new individuals and businesses from contributing to growth in the company's customer base.

Aside from the basic theme of hardship, the second most frequent comment is that Central Hudson's rate structure penalizes customers that try to conserve energy. This issue became prominent because the company's express rationales for its rate application included revenue losses resulting from reduced consumption, caused partly by conservation and efficiency measures. Customers view this as a special form of hardship, in that it defeats their efforts to save money, or as a perverse price signal that discourages environmentally sound choices.

Another theme in the public comments is that Central Hudson fails to provide adequate service in return for its rate increases. Customers express suspicion that the company could operate more effectively. One group of customers alleges that about five of them are served in an antiquated and inadequate pocket of the distribution system prone to chronic failure, and described what they considered an unnecessary five-day outage during the last February's snowstorm. Other customers complain of unresponsive or disrespectful service in less extraordinary circumstances.

An additional area of criticism involves the regulatory process generally. The comments assert that the company's rate requests and its operations have not been examined critically; that public hearings are held without adequate notice; that "regular consumers" were not represented in these proceedings, and that the Joint Proposal was drafted without public participation; that the Joint Proposal's prohibition against rate increases before July 2013 may be unenforceable; and that a one-year rate plan would better acknowledge the unpredictability of present economic conditions. Some of the public comments criticize multi-year plans as inappropriate at a time of economic uncertainty.

To explain how we endeavor to respond to these concerns as part of today's order, the following is a broad description of the principles underlying our decision-making process here and in other rate cases. Some of these issues also are discussed in more detail elsewhere in the order.

We recognize that, when customers face economic difficulties and need to cut costs, generally the firms that provide them goods and services likewise must cut costs or absorb them--as the public comments advocate in this case--in order to keep prices down to an affordable level.

Alternatively, a competitive firm can withdraw from the market if it cannot increase prices to recover its costs. However, because a utility company's customers require continued safe and reliable utility service, and the company is required to provide service to all who request it, a utility company does not have the option of reducing production. Rather, it must continue to collect sufficient revenue to cover the cost of owning and maintaining its infrastructure, even if customers' demand decreases.

While utilities' responses to customers' economic difficulties are therefore limited, we have nevertheless required all utilities in the state to comply with austerity guidelines that require belt-tightening beyond that imposed by our usual regulatory oversight.[9] For example, we have limited the companies' rate allowances on the assumption that they will postpone capital investment projects if they could do so without jeopardizing safe and reliable service, and that they will forgo discretionary salary increases for their executive employees. The rates approved in this order incorporate these principles and presuppose that Central Hudson will comply with our austerity directives.

To set a revenue requirement consistent with these principles, we gather as much information as possible about relevant facts such as the company's costs and how they might be reduced, and its revenues and how they might be enhanced. Here, as in many cases, Staff and other intervenors conducted extensive audits and discovery, consulted their own experts, and thereby prepared evidence (the prefiled testimony and exhibits shown on the DPS website) as a response to the evidence submitted by Central Hudson with its initial rate request.

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[9] Case 09-M-0435, *Utility Austerity Programs,* Notice Requiring the Filing of Utility Austerity Plans (issued May 15, 2009).

Where a party's discovery requests met with resistance, they would be litigated before the Administrative Law Judge. Through this process, the parties challenging the company's rate application reviewed factual questions such as those raised in the public comments.

To address the cost and efficiency issues most prominently cited in the comments, first, we can rely on the evidentiary record regarding a reasonable common equity return. Staff's review has ensured that the return allowed on the company's regulated operations has not been overstated because of factors such as the higher risk associated with the company's investment in alternate power sources or other unregulated activities. Turning to executive salaries, roughly 87% of the 12 executive base salaries and only 63% of those individuals' total compensation is included in rates; thus, any executive compensation exceeding that level would be paid by shareholders rather than customers. Regarding customers' complaints about the company's service, the Joint Proposal's terms include incentive mechanisms which make the company's earnings contingent on whether it meets specific service quality targets.[10]

More generally, Staff and other parties have investigated the numerous expense items inherent in an operation like Central Hudson's, not only for the purpose of holding costs to a minimum and postponing any expenditures that can safely be delayed until the economy improves, but also to make rate adjustments which impute savings and efficiencies that we expect the company to achieve prospectively.

[10] Our staff also will investigate the prolonged outages during the February 2010 snowstorm and the details of the service restoration efforts that followed.

As to the effect of energy conservation and efficiency programs on rates, it is true that we have directed Central Hudson and other utility companies to maintain a revenue decoupling mechanism (RDM) which allows rates to be adjusted to offset conservation-related revenue losses. However, the RDM is not designed to make conservation a source of extra profits for the company, as many of the comments assume. Rather, the RDM attempts to ensure that the utility company cannot increase its profitability by encouraging customers to use more energy. Thus, the RDM helps the public secure the benefits of conservation and efficiency by neutralizing any economic bias, on the utility’s part, in favor of increased consumption. Our staff will work with Central Hudson to ensure that the company’s outreach and educational programs adequately explain how the RDM, and conservation and efficiency in general, not only benefit the environment but also mitigate the costs of service that otherwise would be passed through to customers.

Finally, the third major category of comments summarized above involves concerns about the rate setting process. This rate case, like most, started with filing of the company’s detailed testimony and exhibits regarding its estimated future revenue requirements. Staff’s and the other parties’ initial response was to conduct extensive discovery regarding the details of the company’s operations and expenditures.

In some cases, the next step would be a trial-type hearing before an administrative law judge, to test the witnesses’ opposing presentations. In this instance, as commonly happens, the parties chose instead to enter into settlement discussions after they filed their testimony and developed an appreciation of the strengths and weaknesses of opposing parties’ cases. To encourage a free exchange of proposals, our regulations require that parties entering such negotiations agree to maintain the confidentiality of the discussions. However, the negotiations are open to anyone who commits to confidentiality; and of course the resulting proposal, if any, is subject to extensive public examination and debate, as demonstrated in this case.

An advantage of basing a rate decision on a joint proposal is that the proposal will reflect not only the strengths and weaknesses of the parties' respective litigation cases in the prefiled evidence, but also other rate and service provisions that might not be proposed when setting rates for a single year solely on the basis of a litigated record. Some of the public comments criticize multi-year plans as inappropriate at a time of economic uncertainty. We have considered such concerns, including the comments citing the hardship of any rate increase, in adopting the Joint Proposal's multi-year rate plan in preference to a one-year rate decision. After testing the Joint Proposal's rate plan against general standards of reasonableness as well as our austerity requirements, we expect that its adoption will better protect customers' interests than the larger increases that could have ensued had we determined the Rate Year 1 increase on the basis of the litigated record and without the Joint Proposal's prohibition against new rate applications for the second and third years.

SUBSTANCE OF THE PROPOSED TERMS

The Joint Proposal's major provisions, if adopted, would supplant Central Hudson's rate application as follows.[11]

[11] The points noted here are simply highlights of the Joint Proposal. For a complete statement of its terms, one should rely on the proposal itself, which accompanies this order as Attachment 3 and constitutes a part of the order. The Joint

As noted, the rate plan commencing July 1, 2010 would govern at least the ensuing three years (Rate Years 1, 2, and 3), rather than just the single rate year starting this July 1 which was the original subject of the company's application and the parties' opposing testimony. Instead of the single rate year's electric delivery revenue increase of $26.3 million (10.3%) as indicated by the company's updates to its original application, the increases for Rate Years 1, 2, and 3 respectively would be $11.8 million (4.6%), $9.3 million (3.5%), and $9.1 million (3.3%). For gas delivery revenues, instead of the single rate year's increase of $7.8 million as indicated by the company's updated application, the increases for Rate Years 1, 2, and 3 respectively would be $5.7 million (8.9%), $2.3 million (3.4%), and $1.6 million (2.3%). The rates effective at the start of Rate Year 3 would remain in effect until superseded by new rates, which we could implement at any time after the end of that year.

The parties estimate that the Joint Proposal's rates would allow the typical monthly residential electric bill for combined delivery and commodity service (Service Classification (SC) 1 non-heating, 630 kilowatt-hours (kWh) per month) to increase by $4.42 (4.5%), $3.65 (3.6%), and $2.68 (2.6%) for Rate Years 1, 2, and 3 respectively. (These electric bill impacts would be caused partly by the delivery rate increases in the Joint Proposal itself and partly by the gradual expiration, over Rate Years 1 and 2, of electric bill credits (EBCs) credited to customers in the 2009 rate order.) For gas bills,

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Proposal in turn includes Appendices A through O. In Attachment 4 to this order, we have replaced the interim version of Appendix B filed by the parties, regarding net plant targets, with a finalized version filed by the company May 14, 2010.

the parties estimate that the Rate Year 1, 2, and 3 increases for a typical monthly residential gas bill for commodity and delivery service combined (SC 1 heating, 910 hundred cubic feet (Ccf) per year) would be $5.86 (4.7%), $2.73 (2.1%), and $2.02 (1.5%).

The Joint Proposal's revenue requirements are designed to provide the company a reasonable opportunity of earning 7.4% on its overall capital, based partly on the assumption of a 48.0% common equity ratio and a 10.0% return on common equity.[12] Should the actual earned return on common equity exceed 10.50%, the excess up to and including 11.00% would be allocated equally between customers and shareholders; excesses above 11.00% would be allocated 80% to customers and 20% to shareholders; and excesses above 11.50% would be allocated 90% to customers and 10% to shareholders.

We have required that all Class A electric and gas utilities, such as Central Hudson, formulate and document their actions and plans to address the need for operational savings through austerity in response to the current adverse economic conditions.[13] The Joint Proposal incorporates the following austerity measures: an additional 0.5% productivity imputation, for a total productivity adjustment of 1.5% to capture unidentifiable efficiencies over the term of the rate plan; disallowance of the costs of the Supplemental Executive Retirement Plan (SERP); continuation, through December 2010, of the current freeze on executive salaries recoverable in rates; elimination of costs related to implementation of International Financial Reporting Standards (IFRS) during Rate Year 1 and

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[12] The capital structure and return allowances are shown in detail in Joint Proposal Appendix H, Schedule 1.

[13] Case 09-M-0435, *supra,* Notice Requiring the Filing of Utility Austerity Plans (issued May 15, 2009).

deferral of IFRS costs (up to $375,000) in Rate Years 2 and 3; and capping many expense elements at inflation rates of 1.7% and 1.8% for Rate Years 2 and 3 respectively.

An additional advantage for customers is an asymmetric reconciliation mechanism for any shortfalls in actual net plant additions as compared with higher projected additions in the Joint Proposal. That is, the revenues allowed as a return on net plant additions would be deferred for customers' benefit insofar as the projected additions fail to materialize, whereas the company would bear the risk of carrying costs resulting from any net plant additions in excess of the projected amounts.

Analogously, for several substantial expense categories, shortfalls in actual expense levels (as compared with the Joint Proposal's projections) would be deferred for customers' benefit while the company would bear the risk of overexpenditures. The items subject to this deferral treatment would be tree-trimming for transmission and distribution rights-of-way, economic development programs, stray voltage testing, and depreciation expense related to the gas main replacement program and the net plant addition shortfalls as described above.

Other costs would be subject to bilateral, symmetrical mechanisms whereby expenditure shortfalls and excesses alike would be deferred for the benefit of customers or shareholders, respectively: property tax expense subject to limitations, stray voltage mitigation costs, expenditures for the Enhanced Powerful Opportunity Program (EPOP) for low-income customers up to 15% over the rate allowance, interest on variable rate debt, interest on new issuances of long-term debt in Rate Years 2 and 3, management audit expense, and other items already subject to bilateral deferral pursuant to previous Commission orders.

The Joint Proposal’s electric and gas revenue forecasts are based on compromises between various elements of the forecasts in Staff’s and Central Hudson’s respective testimony. As discussed above, the RDM targets would be updated to continue to neutralize any economic incentive that otherwise would bias the company in favor of sales rather than conservation. Revenue responsibility would be reallocated among service classifications in Rate Year 1 by assigning up to 1.25 times the overall gas or electric system revenue increase to classes that are earning less than 85% of the system average rate of return, and assigning at least 0.75 times the system increase to classes earning more than 115% of the system average rate of return. These parameters imply that SC 1 residential customers would receive rate increases neither more nor less than the system-wide increase. For residential time-of-use customers, the differential between on-peak and off-peak volumetric delivery rates would be phased out by the end of Rate Year 2. Some elements of the Merchant Function Charge (MFC) for Administration, through which customers are billed for various commodity-related costs, would be disaggregated into an MFC Supply component or into base rates.

Other existing programs established in prior rate decisions generally would remain in effect, with modifications including, among others, certain updated expenditure levels; and a transition process to implement a new telephone-based survey of customer satisfaction. Significant programmatic changes include new economic development initiatives, and increased funding for such programs; increased funding for the EPOP and Bill Discount programs for low-income customers; intensified efforts to manage rights-of-way so as to minimize outages; strengthened gas safety incentives to encourage identification and repair of gas leaks and overall reliability; and a new Gas

Construction Quality Assurance Inspection Program to oversee construction and repair projects performed by the company or its subcontractors.

MODIFICATIONS ADDRESSED BY THE PARTIES

After the hearings and briefing in this case were otherwise completed and while the present Joint Proposal was awaiting our review, further proceedings were held to consider proposals and arguments regarding possible modifications of the Joint Proposal in the following two areas.

Levelization

Introduction

While this case was pending, we adopted a three-year electric rate plan for Con Edison.[14] As a method of rate mitigation, that rate plan “levelized” the annual delivery revenue increases; *i.e.,* each year’s increase equals, in dollar terms, the previous year’s increase. The Judge in the present case, citing the Con Edison decision and the related discussion at our deliberative session, established a comment procedure to address the merits of modifying the pending Joint Proposal to provide analogous year-to-year levelization for Central Hudson.[15]

[14] Cases 08-M-0152 and 09-E-0428, *Consolidated Edison Co. of N.Y., Inc. – Rates and Audit,* Order Establishing Three-Year Electric Rate Plan (issued March 26, 2010).

[15] Cases 09-E-0588 and 09-G-0589, Procedural Ruling (issued April 6, 2010). The ruling erroneously stated that each annual increase would equal the previous one in percentage as well as dollar terms, an impossibility because, by hypothesis, the equal dollar increases each year would be added to a base allowance that would increase from year to year.

Comments opposing such further levelization were filed by Central Hudson, Staff, and Multiple Intervenors, while the CPB commented in support.[16] In accordance with a ruling in which the Judge summarized the results of a procedural conference, the company and Staff each presented a proposal to effect levelization, should we require it despite their opposition. Multiple Intervenors, notwithstanding its opposition to any such modification, prefers Staff's version to the company's. The CPB expresses no preference.

Having reviewed the comments including the proposed adjustments, we conclude that the Joint Proposal's year-to-year increases already are sufficiently levelized so that, in this instance, modifying the Joint Proposal to achieve further levelization would not benefit customers sufficiently to justify our rejection of the terms initially negotiated among the parties.

Levelization Method and Impacts

As noted, Staff and Central Hudson each has offered its own version of the modifications we could adopt if, over their objections, we decided to precisely levelize the annual delivery revenue increases.[17] In dollar terms, the only

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[16] Staff, Multiple Intervenors, and CPB comments dated April 16, 2010; company initial comments dated April 17, 2010; company and Staff reply comments dated April 21, 2010.

[17] Central Hudson objects that the Judge, instead of inviting comments, should have required a negotiated levelization proposal. (April 17, 2010 comments.) However, the company does not dispute the accuracy of the Judge's April 6, 2010 ruling summarizing the April 1 procedural conference in which the comment procedure was developed; and the Judge informs us that the participants mentioned the possibility of a joint proposal during the discussion. Multiple Intervenors reports that Staff circulated a levelization proposal during additional discussions after the conference. (Multiple

significant difference between the Staff and company approaches is the cost of capital used to calculate the carrying charge on that portion of the revenue requirement whose recovery would be postponed to the end of the multi-year rate period for the sake of levelization. Staff would apply the "other customer [contributed] capital" rate (OCCR), currently 4.20%, derived from yields on intermediate-term A-rated debt. Central Hudson would apply the overall allowed pre-tax rate of return which, according to the Joint Proposal's terms if adopted, would be 10.65%. Assuming a 4.20% OCCR, Staff projects that levelization as outlined below would cost customers an extra $0.2 million ($140,000 electric and $94,000 gas) in carrying charges over the life of the levelized rate plan, as compared with the Joint Proposal. To use the pre-tax allowed return as Central Hudson proposes would cost customers more than twice the OCCR-based charges, even if the OCCR rose to the 5.29% average level that prevailed for the five years 2006-10.

Aside from that distinction, Staff and Central Hudson both propose a levelization method that would incorporate the Joint Proposal's pre-existing rate provisions. In other words, just as in the Joint Proposal, an annually declining amount of electric bill credits (EBCs) would be used to reduce each year's electric revenue requirement until the EBCs expire at the end of Rate Year 2.[18] As an overlay on this combination of revenue

Intervenors' April 16, 2010 comments, p. 12.) In any event, nothing in the comment procedure precluded the parties from developing a joint proposal on levelization.

[18] At the time of the 2009 rate order at the end of Central Hudson's last previous rate case, $16.0 million of EBCs were available going forward, and we directed the company to apply for customers' benefit $10 million of that amount in the rate year starting July 1, 2010 (Rate Year 1 in the present case) and $6 million in the following year. (2009 rate order,

requirements and EBC phase-outs in the Joint Proposal, the levelization method proposed by Staff and the company (should we require it, over their opposition) would further moderate the electric and gas revenue requirements by superimposing what Staff calls a “bill adjustment credit” in Rate Years 1 and 2 and a “bill adjustment surcharge” in Rate Year 3.[19] The parties propose to rely on credits and a surcharge because these mechanisms could be designed to not only levelize the annual revenue increases, but also preserve the rate design and the RDM targets negotiated in the Joint Proposal and avoid a base revenue reduction at the end of Rate Year 3. Multiple Intervenors emphasizes, moreover, that credits and surcharges alike should be allocated among classes in the same manner as the Joint Proposal’s overall revenue allocation, to prevent inequities and subsidies inconsistent with the Joint Proposal’s negotiated terms.

Table 1 below compares the revenue allowances provided in the Joint Proposal (after taking into account the declining EBCs’ effect on the electric revenue requirement, and excluding revenue taxes) and the levelized results achievable through the bill adjustment credits and surcharge, where the “Rate Year 1 (RY1) delivery revenue increase” takes effect July 1, 2010 and so forth. Each percentage value denotes the increase relative to the previous year’s total electric or gas revenue allowance.

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pp. 37-38.) However, to further mitigate rate impacts, the present Joint Proposal would increase the Rate Year 1 EBCs to $12.0 million instead of $10.0 million, and reduce the Rate Year 2 EBCs accordingly from $6 million to $4 million.

[19] The company calls this arrangement “the Con Edison credit/ surcharge/true-up mechanism.”

TABLE 1

	RY1 Delivery Rev. Increase	RY2 Delivery Rev. Increase	RY3 Delivery Rev. Increase
Electric per JP (after EBC effects)	$19.7M (7.6%)	$17.0M (6.3%)	$12.8M (4.6%)
Elec. Levelized	$17.7M (6.8%)	$17.7M (6.6%)	$17.7M (6.4%)
Gas per JP	$ 5.5M (8.6%)	$ 2.3M (3.3%)	$ 1.6M (2.2%)
Gas levelized	$ 3.8M (5.9%)	$ 3.8M (5.5%)	$ 3.8M (5.3%)

Table 2 shows the increases in monthly delivery-only bills under the terms of the present Joint Proposal, as compared with the Joint Proposal modified for levelization as shown above in Table 1. The amounts shown in Table 2 are the average increases in the monthly bill for a typical residential electric non-heating customer and a typical residential gas heating customer. (These are average monthly figures over the course of a year; thus, for months that fall within the heating season, the numbers shown overstate the monthly impact for electric non-heating customers and they understate the impact for gas heating customers. During the rest of the year, the overstatement or understatement is reversed.)

TABLE 2

	RY1 Bill Increase	RY2 Bill Increase	RY3 Bill Increase
Electric per JP	$4.42	$3.65	$2.68
Elec. Levelized	$3.89	$3.87	$3.86
Gas per JP	$5.86	$2.73	$2.02
Gas levelized	$4.15	$4.22	$4.28

Arguments for and Against Levelization

The CPB, the only party supporting levelization, says the revenue increases in this case are no less dramatic than in two other recent cases where we have required levelization. According to the CPB, we adopt levelization provisions in "many" joint proposals because they mitigate hardship for residential customers under today's adverse economic conditions.[20] As examples, the CPB cites the 2010 Con Edison electric rate case noted above and, before that, our most recent decision regarding gas rates for Orange & Rockland Utilities, Inc.[21] The CPB notes that we adopted a levelized plan offered as one of two options in the Orange & Rockland joint proposal, notwithstanding that no party favored it over the non-levelizing option. The CPB states that the non-levelized Rate Year 1 gas rate increase for Orange & Rockland would have been only 2.6%, as compared with 8.6% in the present Central Hudson joint proposal. (However, we note that these two percentages are not at all comparable, because Orange & Rockland's 2.6% increase in Rate Year 1 would have been the impact on the combined delivery and commodity bill[22] whereas Central Hudson's 8.6% would be the impact on the delivery portion alone.) The CPB goes on to argue that here, as in the Orange & Rockland case, we should strive to avoid front-loading any rate increase onto the initial rate year because customers probably will be better able to pay increased utility

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[20] April 17, 2010 comments, p. 2.

[21] Case 08-G-1398, *Orange & Rockland Utilities, Inc. – Rates,* Order Adopting Joint Proposal and Implementing a Three-Year Rate Plan (issued October 16, 2009).

[22] *Ibid.*, Joint Proposal, Appendix J (Option A, Non-Levelized), Schedule 2, p. 10.

charges after an economic recovery in the rate plan’s later years.

Regarding electric delivery rates, the Joint Proposal’s proponents argue against levelization on the ground that the Joint Proposal already represents a negotiated result intended to balance all relevant and legitimate interests including, but not limited to, mitigation of impacts on residential customers. For example, they say, the Joint Proposal’s annual increases shown above already reflect the sponsors’ considered agreement to mitigate the Rate Year 1 electric rate increase by accelerating the use and exhaustion of electric bill credits (EBCs) as compared with the schedule we adopted in Central Hudson’s 2009 rate order.[23] Multiple Intervenors notes that, without the EBC acceleration already reflected in the Joint Proposal, the Joint Proposal’s rate plan would have required electric delivery revenue increases of $21.8 million, $13.3 million, and $13.1 million for Rate Years 1, 2, and 3 respectively, in contrast to the more levelized bill impacts of $19.7 million, $17.0 million, and $12.8 million resulting from EBC acceleration as shown in Table 1 above.[24]

In another argument related to the thesis that the Joint Proposal’s overall balance of interests should remain undisturbed, Central Hudson alleges an inconsistency between the expectation of an economic recovery in the out years, which tends to support levelization as an attempt at synchronizing

[23] Note 18, above.

[24] Central Hudson correctly observes that the Joint Proposal’s electric rate impacts are caused predominantly by the expiration of EBCs pursuant to the 2009 rate decision, rather than by the Joint Proposal’s revenue allowances going forward. However, that distinction has little relevance to whether we should mitigate the ultimate rate impacts of today’s order, whatever their origin.

rate increase and economic growth, versus certain assumptions underlying the Joint Proposal's overall revenue allowance. In particular, the Joint Proposal in its present form seeks to impose austerity on the company in response to the current economic downturn. The Joint Proposal would accomplish this by limiting some expense allowances to the inflation rate and holding other expenses to austerity levels, for the entire duration of the three-year rate plan. To the extent that levelization assumes an economic recovery while austerity measures assume none, the company concludes that modification of the Joint Proposal for levelization purposes entails a corresponding requirement that the parties be allowed to renegotiate a new, more generous revenue allowance.

Central Hudson also seems to allege an inconsistency insofar as the front-loading of the Joint Proposal's increases is caused partly by revenue requirement mitigators available only in the out years, namely an assumed expense reduction pursuant to Financial Accounting Standard 87 (Employers' Accounting for Pensions) and avoidance of related actuarial losses. Since the resulting moderation of the out year revenue requirement is a benefit to customers, and levelization likewise would be intended to assist customers by moderating the Joint Proposal's front-loading in the initial year, the company finds it incongruous that "the creation of one ratepayer benefit would be employed to justify creating another."[25] We find this argument misguided because the ultimate purpose of levelization would be not to remedy some inequity to customers but to more effectively manage the multi-year revenue requirement over the rate period, regardless of what specific costs or benefits might have determined that overall revenue requirement.

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[25] Company's April 17, 2010 comments, p. 12.

Turning to specific rates, the proponents say the Joint Proposal’s electric delivery rate increases already are so nearly levelized that any further levelization would increase the out year delivery rates compared with those in the Joint Proposal, while the resulting rate reduction in Rate Year 1 would be so slight that it easily could be swamped by even the slightest increase in commodity charges or by even minor surcharges that we might impose for reasons that have yet to be determined. Therefore, the Joint Proposal’s sponsors conclude, the customer savings achievable through further levelization of electric rates in this instance would be so slight, and any resulting assurance against bill increases would be so tenuous, that one cannot justify even the minimum additional carrying costs needed to implement levelization.[26] Contrary to the CPB’s claim that rate impact concerns mandate levelization in this case as clearly as in our Con Edison decision, Central Hudson observes that the reason for levelization in that case was that the year-to-year electric rate increases would have been 10.4%, 5.3%, and 4.6% in rate years 1, 2, and 3 respectively in the absence of levelization. In contrast, the Central Hudson Joint Proposal already provides substantially less front-loaded increases (shown in Table 1 above) of 7.6%, 6.3%, and 4.6%.

As for gas delivery rates, while the increases in the Joint Proposal’s gas rate plan are more front-loaded than in the electric plan, the proponents argue that several other considerations militate more strongly against levelization than

[26] Multiple Intervenors adds that we frequently have adopted rate plans more acutely front-loaded than the plan in the pending Joint Proposal, by allowing a rate increase in the initial year followed by a multi-year rate freeze. However, Multiple Intervenors’ observation, while factually correct, begs the question whether adverse economic conditions mandate a different approach.

in the case of electric rates. First, Staff observes that the gas delivery rate increase to be shifted to the rate plan's out years through levelization would be greater (in percentage terms) than the corresponding shift of electric rate increases. Therefore the out year gas rate increases resulting from such modification of the Joint Proposal would have a more severe bill impact, and the carrying charges borne by customers would be proportionally higher, than in the case of electric delivery rate levelization.

Second, Staff and Multiple Intervenors emphasize that the Joint Proposal's gas rates deliberately are designed to levelize gas delivery rate increases for SC 11 more than for other customer classes, because otherwise the Joint Proposal's bill impacts would have been uniquely onerous for SC 11 insofar as the Joint Proposal would deny SC 11 any share of Central Hudson's revenues from interruptible sales. The credit and surcharges needed to further levelize gas delivery rates for other classes would partly undo the Joint Proposal's existing levelization for SC 11, a result that Multiple Intervenors opposes on the ground that the Joint Proposal's SC 11 levelization enables that class to forgo the benefit of an interruptible revenues imputation without requiring a subsidy from other classes. In that sense, the proponents say, further levelization would directly defeat the Joint Proposal's negotiated balance among competing interests, unless (as Multiple Intervenors requests) we exempted SC 11 from any credit and surcharges we might impose on other classes for levelization purposes.

Third, although Central Hudson concedes that the year-to-year slope of the Joint Proposal's non-levelized percentage gas rate increases is as steeply front-loaded as the non-levelized electric rate increases that we found unacceptable in the Con Edison case, Central Hudson emphasizes that in this case the percentages themselves, and thus the rate impacts, are substantially smaller. While (again) the non-levelized Con Edison electric rate increases would have been 10.4%, 5.3%, and 4.6% in rate years 1, 2, and 3 respectively, the Joint Proposal’s non-levelized gas rate increases here would be only 8.6%, 3.3%, and 2.2%.

In reply to the CPB, the company argues that the Orange & Rockland gas rate plan is not comparable to the plan proposed here because, in dollar terms, the levelized first year increase for Central Hudson would be less than 45% of the levelized first year Orange & Rockland increase ($3.8 million versus $9.0 million, respectively). However, since the issue is whether to use levelization to mitigate customer impacts, these aggregate revenue amounts are not useful because they do not indicate whether the non-levelized bill impacts for Orange & Rockland gas customers would have been more severe than for Central Hudson gas customers in percentage terms.[27]

Conclusions on Levelization

Addressing first Central Hudson’s point that it was unseemly for the CPB to advocate levelization without initially having signed or opposed the Joint Proposal, we find it appropriate that the procedure for comment on levelization was conducted on notice to all parties, because neither the CPB nor any other party previously had an opportunity to consider or

[27] Central Hudson adds that the Con Edison rate decision dealt with total electric revenue increases of $1.1 billion over the period of the rate plan, 100 times more than the $9.7 million gas revenue increase at issue here. Here again, since Con Edison obviously is a larger company, the dollar comparison is not helpful in gauging the rate impacts on the two companies’ respective service territories or their individual customers.

discuss the Joint Proposal's merits in light of the Con Edison rate decision. We also disagree with the company's implication that the CPB waived its standing to discuss aspects of the Joint Proposal by declining to execute it. Had the CPB decided to actively oppose the Joint Proposal, the suggestion of such a waiver would be plainly absurd, and it follows that a waiver is even less readily inferable from the CPB's relative neutrality. In a case such as this, it would polarize and impede the settlement process if we imposed a rule of standing that would curtail a party's opportunity to be heard merely because the party takes a neutral position toward a joint proposal in most respects rather than actively oppose it in its entirety. Moreover, negotiations commonly bring parties to a variety of positions, such that some parties may obtain concessions that win their neutrality while others may find the Joint Proposal sufficiently attractive or repugnant to support or oppose it affirmatively. A rule of standing based on the qualitative degree of a party's neutrality or partisanship, aside from being unmanageable, would be inconsistent with the procedural safeguards in our Settlement Guidelines.

Turning to the merits of levelization, we conclude that it would serve neither the public interest nor the customers' best interests in this instance. The strongest argument for levelization is that, as explained above, this Joint Proposal provides a steeper initial year's increase in the monthly gas delivery bill for typical SC 1 heating customers, at least, than the increase that we decided to mitigate through levelization in the Orange & Rockland gas rate case. However, the two cases are not directly comparable, because only the Orange & Rockland case offered a levelization option negotiated by the parties as part of a joint proposal. Similarly, we levelized Con Edison’s electric rate increases on the basis of a plan negotiated in that joint proposal.

Negotiated terms as such clearly enjoy no presumption of reasonableness, because we must exercise independent judgment in determining whether their adoption would satisfy our legal obligations. Nevertheless, as the parties assert, levelization does alter the balance of interests achieved through a joint proposal and therefore should not be undertaken over the parties’ objections unless it would further a legitimate policy objective. In this instance, considering the degree of levelization already implicit in the Joint Proposal together with the factors that weigh against further levelization, we conclude that the balance should be struck in favor of adopting the annual revenue increases as proposed.

More specifically, as noted above, mitigation of rate increases appears to have been one of the Joint Proposal’s objectives. As a result, all the proposed annual increases except the Rate Year 1 gas rate increase are less than those which justified levelization in the Orange & Rockland and Con Edison cases cited as precedent by the CPB. Indeed, the Joint Proposal’s year-to-year increases already are so nearly levelized that even minor changes due to surcharges or commodity price fluctuations would defeat any attempt to stabilize bills from year to year merely by fine-tuning the base delivery rates as we did in the other cases cited.

Further, even if the magnitude of the Joint Proposal’s Rate Year 1 gas rate increase relative to the Rate Year 2 and 3 increases arguably resembles in some ways the relationship among the non-levelized annual Orange & Rockland gas rate increases, the argument for levelizing the gas rate increases in this case is less persuasive than for Orange & Rockland. In that case, the levelization scenario was part of a negotiated joint proposal regarding the overall revenue allowance and other matters. We agree with Central Hudson that the premise supporting levelization as an *ex post* overlay on the Joint Proposal, namely that economic conditions will improve at a pace that will make rate increases more manageable for customers in the out years, conflicts with other assumptions regarding inflation and austerity which were built into the Joint Proposal's provisions during the negotiations.

We also share Staff's and Multiple Intervenors' related but broader concern that modification of the Joint Proposal's terms in circumstances such as these tends to impede future negotiations by making agreements more risky, and therefore less attractive, for parties. Again, a joint proposal bears no presumption of reasonableness that should deter us from making such modifications upon a showing that the public interest requires it. Nevertheless, some caution is appropriate in this case because the levelization provisions at issue never were considered by the parties, much less advocated, during the extensive litigation and negotiation phases. (Through most of that period, it appeared that levelization could not be a relevant issue, because Staff's case indicated almost no need for a revenue increase until the company filed its November 2009 and January 2010 updates.) As Central Hudson points out, our Con Edison rate order states that a "respite from annual rate cases" is itself a public benefit achievable by adopting a joint proposal's terms.[28] We should not lightly set aside major elements of a negotiated rate plan in circumstances where such action could discourage parties from pursuing other multi-year plans in the future.

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[28] Cases 08-M-0152 and 09-E-0428, *supra,* Order Establishing Three-Year Electric Rate Plan (issued March 26, 2010), p. 10, cited in company's April 17, 2010 comments, p. 15.

These comments should not be construed to mean that we regard mitigation of rate impacts on customers as less important than facilitating the ratemaking process. However, levelization does not reduce customers' overall rate burden. Instead, it achieves a series of equal rate increases by shifting the burden so that year-to-year rate increases become more acute in future years, while the overall revenue requirement is slightly increased as a result of additional carrying charges.

Such concerns did not suffice to deter us from adopting levelization in the Orange & Rockland and Con Edison cases for the sake of rate mitigation in the short term. But they were outweighed, in those cases, by the fact that the non-levelized annual increases would have been comparatively severe and, on the other hand, that the levelization proposals were developed in such a way that we could adopt them without doing harm to the negotiating process. Here, in contrast, the balance of benefits and risks weighs in favor of adopting the Joint Proposal's terms as proposed.[29]

Enhanced Powerful Opportunity Program

Procedural Background

The Joint Proposal's terms include a provision that Central Hudson's low-income program known as the Enhanced Powerful Opportunity Program (EPOP), which we instituted in the 2006 rate order to strengthen a previous program and which is

[29] We recently reached a similar conclusion in deciding not to levelize a rate plan that included a 12.5% increase in gas delivery revenues for the initial rate year, well in excess of the 8.6% increase at issue here. Case 08-G-1392, *St. Lawrence Gas Co., Inc. - Rates,* Order Establishing Rate Plan (issued December 18, 2009), pp. 19-21.

designed to serve 800 to 1,000 participating customers,[30] "will be expanded by a targeted incremental 110 participants per Rate Year. Corresponding incremental funding of $176,000 per Rate Year will be provided. . . . These enhancements will produce total EPOP funding of $1.747 million in Rate Year 1, $1.957 million in Rate Year 2, and $2.170 million in Rate Year 3."[31]

Initially the CPB explained that it had chosen not to oppose the Joint Proposal, notwithstanding the rate plan's allegedly excessive revenue allowances and residential customer charge, because the CPB believed that adoption of the proposed terms would achieve the targeted growth rate of 110 additional participants each year. Subsequently, however, per-participant EPOP costs cited during the evidentiary hearing on the Joint Proposal showed that the annual increment of $176,000 might not suffice to support that many participants. The Judge therefore authorized post-hearing initial and reply briefs to clarify what the Joint Proposal's provision means--particularly whether it prescribes a number of participants or, instead, an expenditure level--and whether we should modify the Joint Proposal's terms accordingly. The CPB, after attempting unsuccessfully to obtain the parties' unanimous consent to disclose elements of the settlement discussions on this subject,[32] moved for leave to file a "surreply" (included with its motion) regarding misstatements and new proposals allegedly advanced in the post-hearing reply briefs. In response, Central Hudson and Staff advocate that we deny the CPB's motion and adopt an interpretation of the Joint

[30] 2006 rate order, p. 35 of April 17, 2006 Joint Proposal.

[31] Cases 09-E-0588 and 09-G-0589, Joint Proposal, Para. X.

[32] Rule 2.6(d) implicitly authorizes such disclosure upon the parties' consent.

Proposal proposed in Staff's post-hearing reply brief.[33]

Procedurally, we shall grant the CPB's motion to the extent its surreply is in the nature of an answer to new proposals appearing initially in the Central Hudson and Staff post-hearing reply briefs.[34] Substantively, we shall adopt the EPOP as proposed in the Joint Proposal, without structural modifications subsequently proposed by the company, Staff, and the CPB in the course of the post-hearing arguments. However, we will clarify our expectations regarding deferral of excess expenditures, strengthen certain reporting requirements, and establish a process whereby we might modify the EPOP in a revenue-neutral manner without awaiting the end of the three-year rate plan.

Controversies Over Per-Participant Costs

In the 2006 rate order, we adopted the EPOP as an enhancement of a previous "Powerful Opportunity Program."[35] The EPOP evolved further in the 2009 rate order, and the pending Joint Proposal would maintain the program in its present form except for the funding increases. Generally, the present EPOP

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[33] The parties' extensive post-hearing motions and briefs on this issue total about 145 pages, including CPB's brief dated March 24, 2010; company's and Staff's replies, dated April 2, 2010; CPB's motion for disclosure, dated April 7, 2010; Multiple Intervenors' e-mail response regarding disclosure, April 8, 2010; CPB's motion and proposed brief dated April 26, 2010; Staff's opposition dated April 29, 2010; company's opposition dated May 4, 2010.

[34] *Cf.* Rule 3.6(3), regarding motions, allowing replies to a response that "seeks relief and effectively constitutes a counter-motion."

[35] Pp. 35-36 of April 17, 2006 Joint Proposal adopted in 2006 rate order.

eligibility criteria are that the customer must take heating service from Central Hudson, receive assistance through the Home Energy Assistance Program (HEAP), have bill arrears of at least $100 remaining after the HEAP grant, and enroll in budget billing. However, a customer that does not satisfy all these criteria may nevertheless qualify for participation in the EPOP if that would improve the customer's likelihood of maintaining uninterrupted utility service without forgoing other essentials.

For customers that do qualify, the EPOP's main features include (1) a Discounted Budget Bill Credit, which may be revoked in case of late payment, of $50 to $225 per month depending on the household's size, income, and energy usage; (2) an Arrears Forgiveness Credit, whereby arrears outstanding at the time of enrollment are exempted from the collection process and are forgiven at a rate of 1/24th per month, if the account remains current, up to a maximum of 24 credits in any 36 months; (3) an Incentive Credit, equal to one's discounted monthly budget bill, applied to the customer's account after the customer pays four consecutive discounted budget bills;[36] and (4) eligibility for education and efficiency measures through the Empower New York program administered by the New York State Energy Research and Development Authority and funded by our Energy Efficiency Portfolio Standard initiative.

The EPOP's three financial components (items (1), (2), and (3) above) may, by their nature, create significant uncertainty as to the EPOP's predicted average cost per customer recoverable through the company's rate allowance. The cost has become increasingly difficult to predict because we substantially modified the EPOP as recently as the 2009 rate

[36] The Joint Proposal would increase the monthly discount to $7.00, $9.00, and $11.00 in Rate Years 1, 2, and 3 respectively.

order last June, when we increased the Discounted Budget Bill Credit, repealed a $2,400 per customer cap on the Arrears Forgiveness Credit, and instituted the Incentive Credit for the first time. The lack of prolonged experience with these changes limits the availability of relevant historic data regarding program costs.

The resulting arguments are presented in extraordinarily voluminous and acrimonious pleadings, which to a large extent are concerned with placing blame for what appear to be shortcomings in the negotiating process. At this stage, however, the only issue appropriate for decision is how the EPOP should be designed starting in July 2010.

Much of the argument arises from differences between the stated objectives of the company and Staff, on one hand, and the CPB, on the other, in the Joint Proposal's parallel provisions (quoted above) for a "targeted" increase of 110 participants annually and a funding increase of $176,000 annually. According to the company, the object of the negotiations was to increase funding, whereas the 110-customer increment was merely a "fall-out" number implicit in the $176,000 amount at the time of the negotiations and was expected to vary if per-participant costs changed. Staff, similarly, defends the $176,000 allowance on the ground that it would provide a reasonable expenditure level without violating our expectation, when we established the program in the 2006 rate order, of a participation level in the range of 800 to 1,000 customers.

In contrast, the CPB's position is based on a belief that customer demand for participation in the EPOP may exceed the customer participation levels accommodated by the program to date. Accordingly, the CPB'S testimony advocated an annual increment of 150 participants, and the CPB later supported the

Joint Proposal's "targeted" annual growth of 110 customers. The CPB complains that the other parties, deliberately or at least carelessly, used stale per-participant cost data to derive the 110-customer target increment from the $176,000 funding increment, thereby inducing the CPB to file an initial statement which lauded the EPOP expansion. The CPB says it would instead have opposed the Joint Proposal as a whole had it believed not only that the rate plan's revenue increases are excessive (as it still does), but also that the Joint Proposal's funding for the EPOP would not support the targeted 110-participant annual growth (as the CPB discovered during the March 9 evidentiary hearing).[37]

Global Remedies - Proposals and Conclusions

Aside from the CPB's motion for a finding of fault or misconduct, the most fundamental remedies proposed in this controversy are the CPB's requests that we reject the Joint Proposal, or curtail the rate plan to two years instead of three, on the theory that the Joint Proposal has been irremediably tainted by deficiencies in the negotiating process and is based on misinformation. However, we agree with Staff and the company that these remedies would be disproportionate to any errors the CPB has alleged. And even if the Joint Proposal were based on misinformation, all parties would have had remarkably abundant opportunities to identify and propose cures

[37] The Joint Proposal is unacceptably ambiguous insofar as it juxtaposes a target customer growth rate and a possibly incongruous dollar allowance. Notwithstanding the parties' attempts to remove the ambiguity by debating their intentions underlying the Joint Proposal, our ultimate objective is not to ascertain their intent as an exercise in contractual interpretation but to determine how to design the EPOP consistently with the public interest.

for any resulting defects in the Joint Proposal during the unusually protracted briefing and hearing process.

As for reducing the rate plan to two years, this would be an overreaction to the evidentiary uncertainties identified by the CPB, in two respects. First, the only aspect of the Joint Proposal they affect is the EPOP cost per participant. Second, it is not essential that the EPOP continue unmodified until the three-year rate plan has elapsed, if we establish at this time that the program is subject to modification before then.

Structural Remedies - Proposals

The next class of remedies comprises proposals by each party to modify the EPOP's design, to eliminate any possibility that high per-participant program costs would prevent achievement of the targeted annual growth rate of 110 participants. Before addressing in detail the controversies regarding per-participant cost estimates, we will resolve two disputes regarding the evidentiary process.

First, the CPB objects to references, in Central Hudson's and Staff's post-hearing briefs, to January 2010 and February 2010 EPOP expenditure data that were not introduced at the March 9 hearing. The CPB is correct that, as a general rule, data offered belatedly should be excluded from consideration unless parties have an adequate opportunity to analyze it and consider what conclusions the data may support. In this case, however, as we explain below, concerns about the reliability of the data lead us to adopt the Joint Proposal's terms provisionally as a means of maintaining the EPOP's present design.

We reach that decision precisely because the post-hearing briefs have revealed the unpredictability of the relevant data and, accordingly, the need to accumulate additional experience with the EPOP in its present form before we can determine whether per-participant costs dictate that the EPOP be modified. Thus, even though we are rejecting at least temporarily the program modifications advocated by the CPB and other parties, our consideration of the late-filed data does not impair the CPB’s legitimate interests, inasmuch as we conclude that the data eventually may validate the CPB’s misgivings about the Joint Proposal’s EPOP provisions.

A second evidentiary and procedural issue is the CPB’s assertion that we should initiate a proceeding to modify our discovery rules because Central Hudson allegedly failed to provide updated interrogatory responses regarding the EPOP’s per-participant costs. If we were to revise our rules as the CPB proposes, obviously we would do so in a forum other than these proceedings. Even then, however, the proposed revision would be untenable because Rule 5.7 already provides that “[a] party shall promptly amend a previous discovery response if, during the course of the proceeding, it learns that the previous response was incorrect when made or, though correct when made, is no longer so in a material respect.” Central Hudson’s failure to expressly calculate per-participant EPOP costs during discovery and negotiations did not violate Rule 5.7. It merely illustrated that the negotiating parties did not engage in the free exchange of information that could have been expected had they been more mindful of their counterparts’ diverse priorities. A new rule to supplement or replace Rule 5.7 would not prevent such problems.

Turning to the substantive disagreements about EPOP cost data, Central Hudson insists that the number of participating customers must increase, all else being equal, because the Joint Proposal provides for increased funding. This truism is not helpful analytically, because the company's "all else equal" proviso ignores the principle that, at some level of per-participant costs, the overall dollar allowance for the EPOP will force the company to reduce the number of participants by excluding or waitlisting eligible applicants. Indeed, in testimony and an interrogatory response, the company reported that budgetary constraints had reduced the number of participating customers, formerly about 1,000, to 940 participants and a 50-customer waiting list.[38] It was in response to the company's July 2009 testimony, which predicted an acceleration of growth in the number of potential participants to 54 per month (rather than the 37 per month in the company's previous rate filing a year earlier), that the CPB's testimony advocated an EPOP designed to accommodate a growth rate of 150 customers per year.

The Joint Proposal's annual funding increment of $176,000, if combined with an annual increase of 110 participants, mathematically would imply an average per-participant cost of $1,600 per year.[39] However, the difficulty that emerged at the March 9 hearing was that, under cross-examination, the company witnesses performed a calculation which seemed to show that the average cost per participant for the second half of 2009, after the program enhancements adopted in the 2009 rate order last June, is $2,588 per year. If that number were valid, it would so substantially exceed $1,600 that it would discredit not only the Joint Proposal's professed target of 110-customer annual growth but also the company's claim that "[s]ince the Joint Proposal *increases* EPOP funding by

[38] Central Hudson testimony; Central Hudson response to Interrogatory CPB-19.

[39] Staff rebuttal testimony, prefiled, 3:5-9.

over 50%, it simply cannot cause a *reduction* in enrollment (other factors being equal)."[40] Instead, assuming that total EPOP spending would be constrained by the Joint Proposal's dollar allowances (*i.e.,* not for lack of eligible applicants), a $2,588 annual cost per customer would require the company to reduce program benefits or the number of participants. It was the resulting discrepancy between the Joint Proposal's stated target participation levels, and those implied by the supposed $2,588 cost per customer, that precipitated the three cycles of post-hearing argument about the EPOP.

Central Hudson subsequently explained on brief that the witnesses had miscalculated their $2,588 estimate during cross-examination by including costs of a low-income program other than the EPOP. But even the company's corrected estimate is $2,100 per customer (based on data for July 2009 through February 2010), still well above the Joint Proposal's implicit $1,600 and therefore inconsistent with the Joint Proposal's "target" customer participation levels. The $2,100 estimate of per-participant costs, if one accepts its underlying assumptions,[41] refutes the CPB's claim that the Joint Proposal's proposed dollar allowances inevitably will require a reduction in the number of participants, compared with current levels. Significantly, however, the $2,100 figure also validates the

[40] Company's April 2, 2010 reply, p. 17 (emphasis in original).

[41] The calculation assumes that participation is constrained by the Joint Proposal's total dollar allowance each year, rather than a lack of eligible and interested applicants; that the low end of the possible range of customer numbers for each year is the participation level that can be funded with 80% of the Joint Proposal's allowance, at an average $2,100 cost per customer; and that over-budget expenditures up to 15% above the Joint Proposal's allowance can be deferred for future recovery, as the Joint Proposal states.

CPB’s point that the Joint Proposal’s reference to a 110-customer annual growth rate is inconsistent with the actual per-participant cost data currently available.

Although Central Hudson attaches less importance to such uncertainties about participation levels than does the CPB or, seemingly, Staff, each of the three parties proposes structural remedies we might apply should we adopt the CPB’s perspective that the paramount concern is the number of participants rather than the total expenditure level. The company’s suggested solution is that we allow deferral and recovery of cost overruns up to 50% over the Joint Proposal’s current allowance in any given rate year, instead of allowing deferral only up to the 15% overrun specified by the Joint Proposal in its present form. The CPB opposes the company’s proposal on the ground that it eventually would tend to increase residential delivery rates, which the CPB deems already excessive from the standpoint of customers not participating in the EPOP. Similarly, although Multiple Intervenors has not addressed the company’s 50% deferral proposal specifically, Multiple Intervenors has said it opposes any modifications of the EPOP that would increase the revenue allowances negotiated in the Joint Proposal.

Staff, on the other hand, would have us maintain the Joint Proposal’s 15% limit on deferrable cost overruns, but discontinue the Incentive Credit which we added to the EPOP in the June 2009 rate decision.[42] Staff estimates that elimination of the Incentive Credit would enable the company to fund an additional 60 participants, all else equal. The CPB objects to

[42] As explained above, the Incentive Credit equals the customer’s discounted monthly budget bill, and is credited to the customer’s account after the customer succeeds in paying discounted budget bills for four consecutive months.

this idea; it argues that the projected 60-customer increment is mere speculation based on the same problematic per-participant cost estimates that have generated the entire EPOP controversy, and that the proposal is offered without any evidence as to how the Incentive Credit may or may not affect customer behavior. Central Hudson's perspective is somewhat similar, in that the company views the combination of the existing program's three credits as a set of interrelated, indispensable features which, only in combination, can "assist the most needy to gain experience with managing utility bills successfully."[43] The company cautions that eliminating any of the credits could undermine the EPOP's objective of retaining participants until they can take full advantage of the program's intended benefits.

Finally, the CPB's proposed solution is to reinstate the $2,400 per customer cap, which we eliminated in the 2009 rate order, on the Arrears Forgiveness Credit.[44] In support of its proposal, the CPB says Staff has testified in favor of a $1,250 cap on a similar credit in another pending rate proceeding.[45] However, Staff's preferred method of reducing per-participant costs in this case would be to repeal the Incentive Credit, as noted. Central Hudson criticizes the CPB's proposal as ineffectual, on the ground that the repeal of the $2,400 cap has not been a significant driver of per-participant costs; using data through calendar 2009 (*i.e.*, the first six months

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[43] Company's April 2, 2010 reply, p. 18.

[44] As described above, under certain conditions the Arrears Forgiveness Credit cancels arrears accrued before the customer became enrolled in the EPOP.

[45] Cases 09-E-0715, 09-G-0716, 09-E-0717, and 09-G-0718, *N.Y.S. Elec. & Gas Corp. and Rochester Gas and Elec. Corp. – Rates,* Tr. 1972-73.

since we removed the cap), the company calculates that continuation of the cap would have reduced per-participant costs by only 5%. The CPB counters that this calculation is no more predictive of customer behavior than Staff's proposal to eliminate the Incentive Credit. More generally, Central Hudson opposes the CPB's proposal in keeping with the company's basic position that, again, we should not eliminate any individual element of the EPOP.

Structural Remedies - Conclusions

For the time being, at least, we agree with Central Hudson that if there are doubts about the EPOP's financial sustainability at a given level of customer enrollment, we should not respond initially by eliminating elements of the program that may be essential to its success. The only definite inference to be drawn from the evidence available at this time is that the Joint Proposal's proponents or the CPB may have been operating under misconceptions about per-participant program costs, because one or more parties were insufficiently attentive to the volatility of those costs over the short period in which the EPOP has operated since the June 2009 program modifications.

Accordingly, we will adopt the Joint Proposal's provisions without eliminating or capping any EPOP credits and without increasing the 15% limit on deferrable excess costs. We share the parties' common interest in achieving an optimum balance between the level of benefits offered through the EPOP, and the level of customer enrollment permitted by the Joint Proposal's overall EPOP funding allowance. To provide the parties an adequate factual basis for deciding what program changes, if any, they may advocate for that purpose, we conclude that the best course available at this time is to continue to monitor program costs and customer behavior--including the degree of customer demand for the EPOP, which may be a function of general economic conditions--until there has been more experience with the combination of EPOP features adopted in the 2009 rate order. (In the next section, we describe the procedures we are adopting for gathering the necessary information and considering possible program modifications.)

To allow the EPOP to be revisited when more data have become available, we are not committing ourselves to leave the EPOP unmodified for the entire duration of the three-year rate plan. On the other hand, to maintain the predictability of the rates and revenue allowances set pursuant to the Joint Proposal’s terms, the Joint Proposal’s EPOP allowed funding levels and the 15% limit on deferrable EPOP cost overruns will remain in effect for the entire three years.

Future Reports and Recommendations

Aside from the remedies discussed and adopted or rejected above, the parties advocate a variety of recommendations as to how additional program data should be compiled, reported, analyzed, and used in administering the EPOP or redesigning it if necessary.

Debate over the Joint Proposal’s EPOP provisions began with the filing of supporting statements. The CPB’s statement, applauding the Joint Proposal’s low-income programs although not endorsing the Joint Proposal as a whole, asked that we modify the Joint Proposal by adding a provision that the company will immediately notify the parties whenever customer participation in the EPOP reaches 95% of the Joint Proposal’s target level for the current rate year; and whenever EPOP expenditures reaches 95% or 110% of that year’s allowance. The CPB said this was based on provisions we were then reviewing in the Con Edison electric rate case, and would provide parties a timely opportunity to consider and advocate options we could adopt in case of imminent fulfillment of the enrollment targets or exhaustion of the annual funding (in terms of either the allowed level or the deferrable excess of up to 15% above the allowance, with notification levels at 95% or 110% respectively).

The CPB's 95%/110% notification proposal was one of two proposed modifications which Central Hudson opposed as untimely in its own statement supporting the Joint Proposal. (The other, pertaining to underspending in a given rate year, will be discussed momentarily.) Initially the CPB responded that it was presenting its proposed modifications after the Joint Proposal was filed because Central Hudson had rejected or ignored them without informing the CPB that the company would omit them when filing the Joint Proposal. However, as a result of the testimony at the March 9 hearing which showed per-participant costs much higher than expected, the CPB withdrew its 95%/110% proposal as moot, reasoning that there no longer was any plausible scenario in which we might consider modifying the EPOP to increase the number of customers that could be served at or below the overall expenditure allowance.

It should go without saying that if, as alleged, Central Hudson did not extend the CPB the courtesy of informing it that the 95%/110% proposal would be rejected in the Joint Proposal, the company has no grounds for complaint that the CPB renewed the proposal in its statement after the Joint Proposal was filed and the omission was discovered. We realize there may be extenuating circumstances that the company has chosen not to explain, possibly as part of its unwillingness to discuss the confidential negotiations surrounding other EPOP issues. Ultimately, however, the CPB's timing is irrelevant because we will adopt the notification requirement on our own initiative. In contrast to the CPB, we find that the factual uncertainties foreclose any attempt to rule out, at this time, scenarios in which EPOP participation levels over the next three years might or might not be constrained by per-participant costs or general economic conditions. The additional notice requirement will be merely an e-mail communication to the parties to report information that Central Hudson undoubtedly will be compiling continuously. As such, we expect it will add almost nothing to the company’s administrative burdens, yet will provide the parties a potentially important signal that the EPOP may require redesign lest the program costs exceed the Joint Proposal’s rate allowance.

Another issue regarding compilation of EPOP data is whether it suffices that Central Hudson provide only quarterly and annual reports, as the Joint Proposal specifies; or whether the company also should provide monthly reports, as the CPB advocates. In testimony and argument, Central Hudson and Staff have opposed a monthly reporting requirement as superfluous. In our view, however, that judgment does not adequately recognize the extent of the factual issues that have emerged since the March 9 hearing and need to be examined in the short run, regarding program costs and customer behavior, so that parties may develop timely programmatic recommendations more persuasive than those permitted by the present record. Here again, we presume that the additional reporting requirement would impose little additional burden on the company as compared with the additional information’s value to the parties and the decisional process.

Accordingly, we will require monthly reports as a substitute for the quarterly reports contemplated in the Joint Proposal, until such time as our Office of Consumer Policy determines that evolving circumstances justify returning to a quarterly schedule. At a minimum, the monthly reports (like the quarterly reports contemplated in the Joint Proposal) should provide customer and cost data both for the most recent reporting period and cumulatively for the current rate year. The reports should show which costs are attributable to each of the EPOP's credits or other benefits, and which are attributable to administration or other general overheads.

A related question is whether, as the CPB asserts, the monthly reports' monthly and cumulative data should include a calculation of per-participant program costs. We conclude that they should. Central Hudson has acknowledged that, given data for enrollment and overall costs, the additional calculation is simple. (Indeed, that has been one of the company's main objections to the CPB's complaint that the company failed to keep parties apprised of changes in per-participant costs during the negotiations.) Therefore, the company has said, it could include the per-participant cost calculation in the quarterly reports with little effort. As noted, the company opposes monthly reporting as a general principle. However, in view of our decision to require monthly reporting, and considering the critical importance of per-participant costs in evaluating possible program modifications, it makes sense to add the minor additional requirement that the reports include such data.

The remaining unresolved issues relate basically to how the EPOP information should be examined and used as it accumulates. First, the CPB has had an ongoing concern about whether the company should be required to exhaust the annual allowed funding in any given rate year, if it has not already done so, by enrolling additional customers in excess of the Joint Proposal's "target" number of customers for that year. Thus, such a directive was one of the proposals advanced in the CPB's initial statement because it allegedly had been ignored when the Joint Proposal was filed. This also was one of the proposals abandoned by the CPB on the theory that, in the aftermath of the March 9 hearing, per-participant costs appeared much higher than originally expected and therefore would preclude any excess funding scenario.

Instead, however, the CPB now advocates a requirement that the company enroll additional customers until it exhausts the 15% margin, above the rate year funding allowance, for which the Joint Proposal would authorize deferral accounting. Central Hudson opposes such a provision on the ground that it would defeat the purpose of the 15% allowance, which, according to Central Hudson, is intended to provide the company partial protection against the consequences of errors in forecasting program costs for a given rate year.

As we have noted in reference to the CPB’s other initial proposal (that Central Hudson notify parties if enrollment or spending reaches 95% or 110% of the levels stated in the Joint Proposal), on the present record we are not ready to presume that the Joint Proposal’s EPOP funding levels will or will not accommodate its targeted enrollment levels. Consequently, we are adopting the CPB’s original proposal that the company be directed to apply any available funds (other than the 15% margin of deferrable expenditures) to enroll participants in excess of the 110-customer annual growth target. This will ensure the maximum participation level achievable within the annual funding constraint, a result consistent with all parties’ objectives as we understand them. What this should mean in practice, however, is that the company will make its best efforts to manage enrollment levels within the basic funding constraint, and not to maximize enrollments by deliberately exhausting the 15% margin as the CPB advocates. As the company says, the 15% overrun provision should be held in reserve as a remedy for forecasting errors. Thus, under the approach we are adopting here, deferral should be available only insofar as the enrollments achieved by exhausting the basic allowance unexpectedly cause expenditures to exceed that allowance.

Yet another unresolved issue involves the CPB's proposed requirement that Staff comprehensively audit the EPOP this July and/or August and issue a report in September, with a view toward developing proposals to modify the program if necessary in response to evolving enrollment and expenditure levels. Central Hudson responds that the audit requirement "is not justified" but that the company has "no objection . . . if Staff believes [it] is warranted."[46] Staff, for its part, says it should not be the only party conducting an audit.

Our staff should exercise its discretion to decide whether the EPOP requires an audit, strictly speaking, which ordinarily would be a response to programmatic failures or accounting irregularities rather than the discovery problems of which the CPB complains. It may suffice that the parties merely compile cost and participant data to show whether the program should be modified for reasons such as they have cited in these proceedings. Parties engaged in reviewing the data also should bear in mind that (as discussed below) we are instituting a collaborative in which program data might prove helpful or necessary. Further, we agree that our staff need not be the only party monitoring the EPOP; but of course other parties' involvement is not a matter for us to decide, provided that all interested parties receive the reports we are prescribing here.

Finally, Staff and the CPB have advanced competing proposals for a collaborative process to identify program changes that might appear appropriate after additional

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[46] Company's April 2, 2010 reply, pp. 24, 26.

experience with the EPOP in its present form. Such review will help dispel the uncertainty whether the Joint Proposal’s allowed expenditures are consistent with its targeted participation levels. The CPB says any program changes should be based on the parties’ analysis of the Staff report advocated by the CPB for September 2010. Staff initially proposed that a collaborative convene after June 2011, when two years of data will have been compiled since adoption of the EPOP’s present features last June in the 2009 rate order.[47] However, Staff now appears to acknowledge that relief for low-income customers, such as the EPOP, is too urgent a matter to be deferred for another year.

Accordingly, the parties should initiate a collaborative to begin immediately, in which they will have an opportunity to consider updated information as it becomes available in the company’s reports (subject to audit or other discovery if necessary). The progress of the collaborative will determine whether program modifications are in order and, if so, they should be presented to us as a joint proposal. Any recommendations resulting from the collaborative should be filed with the Secretary. Should the parties fail to reach agreement, we will establish a procedure for considering their arguments.

To avoid undermining the predictability of the rates adopted in today’s order, we will not adopt proposals to modify the EPOP during the three-year rate plan by increasing the revenue allowance for the program either directly, or indirectly by increasing the 15% limit for deferrable excess costs.

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[47] Staff proposes that the collaborative focus on the future of the Arrears Forgiveness Credit and the Incentive Credit because these may be the two main drivers of EPOP program costs. As noted, however, the available evidence may not support that conclusion, which therefore is better left for additional examination as part of the collaborative.

Rather, the collaborative will provide an opportunity for parties to consider possible program modifications, and to weigh the relative importance of possible objectives such as eliminating waiting lists, increasing the benefits to participants, and/or increasing the number of participants.

COMPLIANCE WITH THE PUBLIC INTEREST

We find that the Joint Proposal's sponsors have satisfied their burden of showing that adoption of the proposed terms would satisfy the Public Service Law's requirement of safe and adequate service at just and reasonable rates. The proposed terms also meet the criteria set forth in our Settlement Guidelines in that they have won the support of ordinarily adversarial parties and have been offered for examination in an evidentiary hearing.[48] Moreover, the proposals result from a process that began with a fully documented rate application, followed by extensive and aggressive discovery, Staff and intervenor testimony, and company rebuttal.

The Joint Proposal exemplifies a multi-year rate plan well designed to serve the primary interests of both the utility company and its customers, by providing the company the revenues and direction needed to provide safe and adequate service over a an extended planning horizon yet minimizing the impact of rate increases on individual customers and on the service territory as a whole. As discussed above, the rate plan would restructure the EBCs to provide customers additional relief in the first two years and thus postpone any additional rate burden so that, insofar as reasonably possible, it will occur in the plan's later years when economic conditions may have improved. In

[48] Cases 90-M-0255 *et al., Procedures for Settlements and Stipulation Agreements*, Opinion No. 92-2 (issued March 24, 1992), Appendix B, p. 8.

turn, the expectation of cost recovery in the out years would hold shareholders harmless and provide them the assurance they require in order to maintain the company’s access to necessary capital.

Another important feature of the Joint Proposal, in view of the clear imperative emerging from the public comments that we address adverse economic conditions in the Central Hudson service territory, is that it would significantly strengthen the company’s economic development programs. The company would commit up to $1.0 million annually, almost double the current amount, for the development programs known as (1) Regional Marketing; (2) Substation Operations and Maintenance Credit; (3) Attraction & Expansion; (4) Shovel Ready; (5) Revitalization; and an additional new program, (6) Wired Innovation Centers, which would provide funds needed by entrepreneurs or start-up companies to wire buildings for electrical equipment. Under the Joint Proposal, programs (1) and (2) would continue in their present form, while (3), (4), and (5) would be modified and expanded to provide greater benefits. (The current “Retention Program” would be discontinued.)

The Joint Proposal is designed to manage the company’s revenue requirement effectively not only through judicious timing of the increases, as discussed above; but also by disallowing cost increases altogether where this can be done consistently with the company’s service obligations and without setting the stage for revenue deficiencies that might demand extraordinary rate increases at the end of the three-year rate period. As a result, as shown in Attachment 1*, about* 80% of the electric revenue increases allowed under the Joint Proposal are attributable to increases in four major categories of operating costs that are essential to the company’s operations or to its customers: property taxes (43%), infrastructure additions (17%), uncollectible accounts expense (13%), and low-income programs (7%). For gas revenues, the comparable figures show that 90% of the increases are driven by essential functions: the RDM adjustment (42%), property taxes (25%), infrastructure additions and removals (21%), and uncollectibles (5%).

As to the remainder of the increases, involving costs for which the rate allowances are more judgmental or discretionary, the Joint Proposal reflects compromise results consistent with the record yet more favorable to customers than allowances that could have resulted from litigation without a negotiated settlement. Thus, for example, adoption of the Joint Proposal’s terms would hold a majority of the expenses to the general rate of inflation; assume approximately a 1% headcount reduction despite the provision of expanded services and programs; provide for numerous one-way deferrals to protect customers from any potential excess of rate allowances over actual spending; and impose an earnings sharing mechanism, which would provide the company an incentive to minimize its costs and improve its efficiencies while allowing customers a share of the savings resulting from those efforts.

As an additional conservatism, costs that normally would have been updated for known changes in our decision at the end of an 11-month rate proceeding have instead been updated only through November 2009 (or, for property taxes, January 2010). Further, as previously mentioned, adoption of the Joint Proposal’s terms would include the following austerity measures: eliminate a Supplemental Executive Retirement Plan (SERP), saving $860,000 annually; limit the deferrable costs of implementing International Financial Reporting Standards (IFRS) to $375,000 over the three rate years, instead of the $750,000 requested for that period; extend a current freeze on executive salaries, through December 2010; and impute unidentifiable productivity improvements of 1.5%, rather than the 1% we customarily applied before initiating our current austerity requirements.

Another advantage of the Joint Proposal's terms, as compared with a litigated result, is that their adoption would mitigate the impact of unforeseen forecasting errors or under-spending by deferring discrepancies between projected costs in various categories and actual results. As described above, a significant portion of such deferrals would operate asymmetrically, providing customers the benefit of expenditure shortfalls while the company would bear the risk of overruns; and, even in those cost categories where deferrals would be bilateral and could benefit either customers or the company, the deferral mechanism would serve both parties' interests by avoiding some of the risk of the uncertainties that would result from a rate decision based on litigation alone.

We expect that adoption of the Joint Proposal's 7.4% allowance for the overall cost of capital, based on a 10.0% cost of common equity and a 48.0% common equity ratio, would enable the company to maintain the strong credit ratings it currently enjoys; thus, we would secure the company's ability to obtain necessary financing over the period of the rate plan, while avoiding excessive capital costs which would contribute to higher revenue requirements and rates. The 7.4% allowance is based partly on a 5.1% cost of long-term debt, which is consistent with the relatively low cost of debt under current economic conditions; but the Joint Proposal would acknowledge the uncertainties as to economic prospects during the three-year rate period, by allowing deferral of shortfalls or excesses in Rate Years 2 and 3, relative to the projected debt costs, for the benefit of customers or shareholders respectively. The overall allowed return would be higher than allowed in the 2009 rate order, but only because of increases in the equity ratio and the cost of debt.

The Joint Proposal's allowed return also would consistent with Staff's litigation testimony regarding the cost of equity. For purposes of setting rates for a single rate year, in contrast to the company's testimony advocating that we continue the 10.0% equity cost allowance adopted in the 2009 rate decision, the cost of equity methodology presented in Staff's testimony (if updated to the time of the Joint Proposal) supports a 9.65% cost of equity. Thus, the Joint Proposal's 10.0% allowance reflects a 35 basis point "stay-out" premium which would reasonably compensate shareholders for the risks the company undertakes by forgoing any additional rate increase for three years. At the same time, the resulting 10.0% allowance would be less than currently allowed in multi-year rate plans for other companies.[49]

As noted, the Joint Proposal includes an earnings sharing mechanism whereby customers would be allocated 50% of any equity return exceeding 10.5% for any single rate year, 80% of excesses over 11.0%, and 90% of excesses over 11.5%. These percentages likewise are more advantageous for customers than those we have adopted most recently.[50] As is true of earnings sharing mechanisms generally, the sharing arrangement protects customers from having to support excessive company earnings, while also giving the company an incentive to enhance its earnings by controlling costs and thus, incidentally, to

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[49] See, *e.g.,* Cases 08-M-0152 and 09-E-0428, *supra,* Order Establishing Three-Year Electric Rate Plan (issued March 26, 2010), allowing 10.15%.

[50] *Ibid*.

minimize the financial pressure for rate increases at the end of the multi-year plan.

To the extent that the Joint Proposal's rate allowances are based on sales and revenue forecasts, the underlying data are reliable and reasonably approximate the results of a fully litigated case. For revenues from electric service, the Joint Proposal incorporates the forecasts in Staff's testimony, which are based on historic results with corrections and updates for Rate Year 1. For gas revenues, the differences between the company and Staff testimony concerned primarily usage per customer, a variable that would be accounted for in the Joint Proposal's RDM adjustment provisions; otherwise, the Joint Proposal generally incorporates the revenue projections from the parties' testimony.

Regarding class revenue allocations and rate design, the Joint Proposal's terms comport with our policy of moving rates toward conformity with the cost of service, but doing so gradually to avoid unreasonable bill impacts. The Joint Proposal's allocation of revenue responsibility among service classifications would produce results that would reduce disparities between the average rate of return generated by the electric or gas system as a whole and the rates of return specific to individual classifications. The existing class returns were a matter of controversy because Staff testified that they should be calculated on the basis of not only *pro forma* cost of service studies, as the company advocated, but also historic results. The Joint Proposal reflects Staff's approach. As noted above, the class rates of return indicated by this method would serve as the basis for assigning limited increases or decreases in revenue responsibility to those classes which are generating less than 85% or more than 115% of the system average return.

For specific rates, the minimum charges (as distinguished from usage-based charges) proposed by Staff in testimony generally were lower than those advocated by Central Hudson, with the proviso that we should assign the minimum charges any incremental revenue responsibility resulting from a decision to grant the company an overall revenue increase greater than Staff proposed. In deference to Multiple Intervenors' concerns about rates for large customers, the Joint Proposal would rely on the cost of service studies to provide substantially larger customer charges than Staff advocated for electric SC 3 and SC 13, and it also would provide a larger customer service charge for gas SC 11. Otherwise, the Joint Proposal incorporates the customer charges advocated in Staff's testimony.

As noted, the Joint Proposal's terms would eliminate time-of-use delivery rates for residential customers (SC 6). In their respective litigation cases, the company proposed this change and Staff agreed, because the rate differential between on-peak and off-peak usage no longer is needed to reflect a difference in the cost of service now that the rates reflect only delivery costs and not commodity costs. Because of disagreements about the bill impact of eliminating SC 6 service, Staff advocated a gradual phase-out while the company favored immediate termination. The Joint Proposal incorporates Staff's approach, phasing out the service over Rate Years 1 and 2. Here again, adoption of the proposed terms therefore would promote our policies of moving rates toward costs while avoiding unnecessarily harsh bill impacts.

Other rate design or tariff modifications under the Joint Proposal would benefit customers by modifying the electric RDM to better synchronize billed and targeted monthly revenues; and by modifying the gas RDM so that it will respond to revenues per service classification, rather than per customer, when actual customer numbers lie between the company's litigation forecast and Staff's higher litigation forecast. To better reflect the cost savings and public benefits achievable by shifting usage to off-peak hours, the Joint Proposal's terms would modify the Hourly Pricing Provision by lowering the threshold for mandatory time-of-use pricing to 300 kilowatts (kW) instead of the current 500 kW. Adoption of the Joint Proposal's terms also would better align prices with costs by restructuring the Merchant Function Charge as described above.

Finally, the Joint Proposal includes provisions to maintain or strengthen various elements of the existing incentive system, which attaches economic consequences to Central Hudson's achievements or shortcomings in providing safe and adequate service. The Service Quality Performance mechanism adopted in the 2009 rate order would continue, with $1.9 million in potential negative revenue adjustments at stake. Half of that amount would be related to the Customer Satisfaction Index (CSI), which measures customer satisfaction after transactions with the company, and half would be related to the PSC Complaint Rate. The company would be required to submit a plan, within 90 days from today's order, to upgrade the CSI procedures by establishing an Interactive Voice Response telephone survey as a substitute for the mailed questionnaires currently in use. We expect this would provide more accurate and timely results, while reducing the cost of gathering customers' responses.

The Joint Proposal's terms also would continue the existing incentives for Central Hudson to maintain electric service reliability, with the addition of financial consequences dependent on whether the company achieves a targeted amount of tree trimming on distribution rights-of-way by 2011.

Finally, the Joint Proposal includes a new and more stringent regime of financial consequences contingent on whether the company meets targeted goals for the number of repairs of previously identified gas leaks, the number of active leak code violations, the number of incidents involving damage to gas facilities, and the rate at which the company replaces leak-prone pipe. Central Hudson also would undertake a new quality assurance program to improve the company's and its contractors' adherence to proper construction practices and operation and maintenance procedures. These measures would reinforce the company's commitment to the diverse efforts essential for the provision of safe and adequate gas service.

CONCLUSION

For the reasons stated above, we find that our adoption of the proposed terms, together with the updates and clarifications described in this order, will serve the public interest and satisfy our statutory obligation to ensure safe and adequate service at just and reasonable rates pursuant to Public Service Law §65 and §66. Accordingly, we will direct the company to file tariff revisions consistent with these findings.[51]

[51] In adopting the Joint Proposal's terms, we neither reject nor adopt the terms stated in §XIV.A. through E. of the Joint Proposal ("Additional Provisions"), as they concern only the parties' mutual obligations. Nothing in the Joint Proposal would preclude reliance on our order adopting the Joint Proposal's terms as precedent in other cases. See Cases 06-G-1185 and 06-G-1186, *KeySpan Energy Delivery – Rates*, Order Adopting Gas Rate Plans (issued December 21, 2007), pp. 58-60.

The Commission orders:

1. In accordance with the foregoing discussion, and subject to the determinations and understandings set forth above, the terms of the joint proposal filed in this proceeding February 3, 2010 are adopted in their entirety unless otherwise noted and are incorporated as part of this order.

2. Central Hudson Gas & Electric Corporation (the company) is directed to file a cancellation supplement, effective June 25, 2010 on not less than one day’s notice, canceling the tariff leaves listed in Attachment 2 to this order.

3. The company is authorized to file on not less than one day's notice, to take effect on or after July 1, 2010 on a temporary basis, such further tariff changes as are necessary to effectuate the provisions adopted in this order.

4. The company is directed to file such further tariff changes as are necessary to effectuate the Rate Year 2 and Rate Year 3 rates provided for in this order. Such changes shall be filed on not less than 30 days’ notice to be effective on a temporary basis on the July 1 commencement of each rate year.

5. The company shall serve copies of its compliance filings upon all parties to these proceedings. Any comments on the compliance filings must be received at the Commission’s offices within ten days of service of the company’s proposed amendments. The amendments specified in each compliance filing shall not become effective on a permanent basis until approved by the Commission and will be subject to refund if any showing is made that the revisions are not in compliance with this order.

6. The requirement of §66(12)(b) of the Public Service Law that newspaper publication be completed prior to the

effective date of the proposed amendments is waived with respect to the tariff changes for Rate Year 1, provided that the company shall file with the Commission, not later than August 12, 2010, proof that a notice to the public of the changes proposed by the amendments and their effective date has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments. The requirements of Public Service Law §66(12)(b) are not waived with respect to the Rate Year 2 or Rate Year 3 filings or with respect to tariff filings in compliance with this order made in subsequent years.

7. The Secretary at her sole discretion may extend the deadlines set forth in this order.

8. These proceedings are continued but shall be closed by the Secretary as soon as the compliance filings have been completed, unless the Secretary finds good cause to continue them further.

By the Commission,

Jaclyn A. Brilling

Digitally Signed by Secretary
New York Public Service Commission

JACLYN A. BRILLING
Secretary

Attachment

Electric

CH Filed Request as compared to CH Filed Request Including Updates, Corrections, & Modifications

Item		
CH Filed Request		$15,207,000
CH Filed Request for use of Deferrals for Distribution ROW Maintenance Expense		$5,700,000
CH Total Filed Request		$20,907,000
CH Filed Request Updated		$26,315,000
Difference		$5,408,000
Detail:	Impact on Requested Increase	% of Total Impact on Requested Increase
Increase in Forecasted Base Revenues	$ (1,400,000)	-26%
Uncollectible Accounts	$ 1,460,000	27%
Regulatory Commission Expense	$ (663,000)	-12%
Property Tax Expense	$ 5,403,000	100%
Other	$ 608,000	11%
Total	$ 5,408,000	100%

Gas

CH Filed Request as compared to CH Filed Request Including Updates, Corrections, & Modifications

Item		
CH Filed Request		$3,997,000
CH Filed Request Updated		$7,831,000
Difference		$3,834,000
Detail:	Impact on Requested Increase	% of Total Impact on Requested Increase
Decrease in Forecasted Base Revenues	$ 1,600,000	42%
Uncollectible Accounts	$ 368,000	10%
Property Tax Expense	$ 1,711,000	45%
Other	$ 155,000	4%
Total	$ 3,834,000	100%

Electric

Rate Year 1 Rate Drivers

Item		
JP RY 1 Rate Increase		$11,815,000
Detail:	Impact on Rate Increase	% of Total Impact on Rate Increase
Increase in Forecasted Base Revenues	$ (1,888,000)	-16%
Increase in Forecasted Other Operating Revenues	$ (1,041,000)	-9%
Distribution ROW Maintenance Expense	$ 2,237,000	19%
Pension Expense	$ (1,447,000)	-12%
Uncollectible Accounts	$ 1,541,000	13%
EPOP and Low Income Program	$ 783,000	7%
MGP Cost Recovery	$ 1,379,000	12%
Property Tax Expense	$ 5,094,000	43%
Depreciation Expense	$ 803,000	7%
Impact of changes to Rate Base	$ 2,000,000	17%
Impact of changes to Rate of Return	$ 1,442,000	12%
Other	$ 912,000	8%
Total	$ 11,815,000	100%

Gas

RY 1 Rate Drivers

Item		
JP RY 1 Rate Increase		$5,709,000
Detail:	Impact on Rate Increase	% of Total Impact on Rate Increase
Decrease in Forecasted Base Revenues	$ 2,419,000	42%
Increase in Forecasted Interruptible Sales	$ (450,000)	-8%
Direct Labor Expense	$ 436,000	8%
Uncollectible Accounts	$ 294,000	5%
Excess Cost of Removal	$ 451,000	8%
Property Tax Expense	$ 1,444,000	25%
Impact of changes to Rate Base	$ 753,000	13%
Impact of changes to Rate of Return	$ 395,000	7%
Other	$ (33,000)	-1%
Total	$ 5,709,000	100%

SUBJECT: Filings by CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Amendments to Schedule P.S.C. No. 15 – Electricity

Third Revised Leaf No. 205.2
Fifth Revised Leaves Nos. 179, 196, 218.2
Sixth Revised Leaves Nos. 163.5.2, 231
Seventh Revised Leaf No. 262
Eighth Revised Leaves Nos. 218.1, 221
Ninth Revised Leaves Nos. 205.1, 219
Tenth Revised Leaves Nos. 165, 184.2.1, 185, 217, 222, 226
Eleventh Revised Leaves Nos. 104, 169, 205, 218, 220, 246
Twelfth Revised Leaf No. 246.1
Thirteenth Revised Leaf No. 210
Supplement Nos. 43, 46

Amendments to Schedule P.S.C. No. 12 – Gas

Sixth Revised Leaves Nos. 121, 195
Eighth Revised Leaves Nos. 151, 153
Ninth Revised Leaves Nos. 152, 158
Tenth Revised Leaves Nos. 126.1, 181, 193
Twelfth Revised Leaf No. 188
Thirteenth Revised Leaves Nos. 149, 186, 191
Supplement Nos. 34, 36

Public Service Commission
State of New York

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service	:	Case 09-E-0588
Proceeding on Motion of the Commission as to the Rates Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	:	Case 09-G-0589

JOINT PROPOSAL

Appendices

Public Service Commission
State of New York

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service	:	Case 09-E-0588
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JOINT PROPOSAL

I. INTRODUCTION

This Proposal ("Proposal") for the resolution of all issues in the above-captioned cases is made jointly by Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company"), the Staff of the Department of Public Service ("Staff") and Multiple Intervenors ("MI")(collectively the "Signatory Parties").

A. Factual Background

On July 31, 2009, Central Hudson filed with the Commission proposed tariff leaves and its case-in-chief in support of proposed increases in its electric and gas delivery revenues based on a rate year ending June 30, 2011. On August 25, 2009, the Commission suspended the submission through December 27, 2009.[1]

Discovery was commenced by Staff and other parties. To date, Staff tendered a total of 414 information requests to the Company, CPB tendered 69, and MI tendered 141.

On September 17, 2009, a Procedural Conference was held by Administrative Law Judge ("ALJ") Rafael A. Epstein, at which, among other things, a two-track schedule (one assuming a settlement and the other assuming a litigated proceeding) was established.[2] Thereafter, motions concerning pre-filed testimony and discovery were filed by CPB and Staff. They were resolved in Judge Epstein's rulings dated October 21, 26 and November 9, 2009.

On November 11, 2009, a Notice of Impending Negotiation was served by the Company on the Active Parties and submitted to Judge Epstein. On November 17, 2009, testimony was filed by Staff (eleven witnesses or panels) and CPB (two witnesses). On December 23, 2009, rebuttal testimony was filed by Central Hudson (eleven witnesses or panels), Staff (one witness) and CPB (one witness). To date, Central Hudson tendered 111 information requests to Staff and seven to CPB.

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1 On December 2, 2009, the rates were further suspended through June 27, 2010.

2 See, Procedural Ruling dated September 28, 2009.

B. Settlement Discussions

On November 24, 2009, pursuant to the Procedural Schedule and the Notice of Impending Negotiation, the parties met at the Commission's Offices in Albany to begin settlement discussions. Additional settlement discussions were held in the Commission's Albany Offices on December 1, 7, 8, 15, and 22, 2009 and January 4, 2010.[3]

II. TERM

The term of this Proposal is three years, commencing July 1, 2010 and terminating June 30, 2013. Each twelve-month period starting on July 1 and ending on June 30 is called a "Rate Year." The provisions of Rate Year 3 (July 1, 2012 through June 30, 2013) will, unless otherwise specified herein, remain in effect until superseding rates become effective.

Nothing herein precludes Central Hudson from filing a new general electric or gas rate case prior to June 30, 2013, for rates to be effective on or after July 1, 2013. Except for minor rate changes and Commission-required rate changes permitted by item XIV.G of this Proposal, the Company will not initiate rate changes to become effective prior to July 1, 2013.

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[3] On December 3, 2009, the Company and Staff jointly requested the appointment of a settlement judge. On December 4, 2009, the Chief Administrative Law Judge appointed Judges Bouteiller and Stegemoeller as settlement judges.

III. REVENUE REQUIREMENTS

A. Revenue Requirements

The revenue requirements for the Rate Years ending June 30, 2011, 2012 and 2013 are shown in the Electric and Gas Income Statements set forth in Appendix A.

B. Delivery Revenue Increases

The delivery revenue increases for electric and gas service are shown in the table below:

	RY1 ($000,000)	RY2 ($000,000)	RY3 ($000,000)
Electric	11.815	9.338	9.054
Gas	5.709	2.363	1.647

C. Electric Bill Credit

Consistent in concept with the approach incorporated into the Commission's June 22, 2009 Order Adopting Recommended Decision With Modifications ("2009 Rate Order") in the preceding Central Hudson rate case, Electric Bill Credits of $12 million in Rate Year 1 and $4 million in Rate Year 2 will be applied per the methods employed under the 2009 Rate Order.

D. Certain Treatments Incorporated in Income Statements

1. Distribution ROW Tree Trimming

The electric Income Statements set forth in Appendix A incorporate the following funding for distribution ROW tree trimming: Rate Year 1 - $12.5 million; Rate Year 2 - $12.691 million; and Rate Year 3 - $11.397 million. The scope of activities for distribution tree trimming includes completing the first cycle of the Modified Enhanced Program by December 31, 2011. Any funding remaining unexpended after completion of the Modified Enhanced Program will be used for the Enhanced Line Clearance Program.

At the end of Rate Year 3, the actual total expenditures for distribution ROW tree trimming will be compared to the sum of the above rate allowances and the cumulative, three-year total of any under-spending will be deferred as of the end of Rate Year 3. 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.

2. Stray Voltage Testing

The electric Income Statements set forth in Appendix A incorporate the following funding for Stray Voltage Testing non-labor expenditures: Rate Year 1 - $2.25 million ($1.9 million for all costs excluding mitigation + $0.350 million for mitigation); Rate Year 2 - $2.311 million ($1.96 million for all costs excluding mitigation + $0.350 million for mitigation); and Rate Year 3 - $2.373 million ($2.023 million for all costs excluding mitigation + $0.350 million for mitigation).

Actual Stray Voltage Testing expenditures, excluding mitigation costs, will be compared to the above rate allowances on a Rate Year basis. Any under-spending as of the end of a Rate Year, exclusive of expenditures for actual mitigation costs, will be deferred for future return to customers with carrying charges at the PTROR.

Actual mitigation costs in each Rate Year will be compared to the rate allowances set forth above. The differences between the rate allowance and actual mitigation expenditures will be deferred for future recovery by the Company, or return to customers, with carrying charges at the PTROR.

3. Austerity

Consistent with the Commission's Policy, as articulated most recently in its Order Approving Ratepayer Credits (issued and effective December 22, 2009) in Case 09-M-0435,[4] the revenue requirements and Income Statements shown in Appendix A incorporate the following adjustments to the Company's gas and electric expenses: an additional 1/2% productivity for a total of 1 1/2% in each Rate Year, establishment of zero current rate allowances for the costs of the Supplemental Executive Retirement Program, and the deferral of costs of planning for and implementing International Financial Reporting Standards

[4] As stated at 3 of the Order: "Accordingly, through 2010, we anticipate that all rate filings and all joint proposals submitted to the Commission will identify, for austerity purposes, discretionary spending cuts. Until the current economic downturn reverses, utilities should employ as many cost-cutting measures as possible. These measures could include, but are not limited to, limiting training of employees in only safety-related or legally-mandated areas, freezing managerial salaries, foregoing managerial bonuses, and limiting travel."

("IFRS") in Rate Years 2 and 3. Additional austerity includes the July-December portion of the Company's prior commitment to freeze executive salaries for 2010.

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 Proposal that may be thought to be to the contrary. 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 Years 1, 2 and 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 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 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 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 and other interested parties by March 1, 2011, 2012, 2013, and 2014 a report on its capital expenditures during the prior calendar year using the format of the spreadsheets set forth in Appendix D.

B. Reservation

Nothing in this Proposal is intended to alter the Company's flexibility during the term hereof to substitute, change, or modify its capital projects.

V. ACCOUNTING MATTERS

A. Other Deferral Accounting

1. Continuing Deferrals

The Company is authorized to continue its use of deferral accounting with respect to the following expense and costs, and all other expenses and costs for which Commission authorization for deferral accounting is currently effective whether by reason of Commission Order or policy of general applicability or by reason of a Commission determination with specific reference to the Company:

a) Pension Expense under Statement of Financial Accounting Standards No. 87;

b) Post Employment Benefits Other than Pensions ("OPEB") under Statement of Financial Accounting Standards No. 106;

c) Manufactured Gas Plant ("MGP") Site Investigation and Remediation Costs;

d) Interest Costs on Variable Rate Debt;

e) Interest Costs on New Debt Issuances in Rate Year 2 and Rate Year 3;

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

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

h) Enhanced Powerful Opportunities Program ("EPOP");

i) New York State Assessment and PSC General Assessment;

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

k) Revenue Decoupling Mechanisms (Electric and Gas);

l) Deferred Temporary Metro Transit Bus Tax Surcharge;

m) Deferred Unbilled Gas Revenues;

n) System Benefit Charge ("SBC") Electric, Gas and Gas Low Income Programs;

o) Renewable Portfolio Standards ("RPS") and Energy Efficiency Portfolio Standards ("EEPS");

p) Sag Mitigation Costs-Capital Projects;

q) Economic Development Plan implementation; and

r) Competition Education Campaign Program.

2. 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 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 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 per Rate Year.

3. Governmental Actions

The Company is authorized to defer the revenue requirement effect of new legislative, governmental and PSC or other regulatory actions subsequent to the execution hereof that individually have material (2% of net income available for common by department) consequences for any element of cost, with carrying charges at the PTROR.

4. IFRS and IT Expense

The Company is authorized to defer its actual non-labor costs of planning for and implementing IFRS incurred in Rate Year 2 and Rate Year 3 subject to a cap on the total principal amount of $375,000 (exclusive of carrying charges), and its actual incremental IT expense costs incurred in Rate Year 3 subject to a cap on the total principal amount of $125,000 (exclusive of carrying charges), and to apply carrying charges at the PTROR.

5. Commodity-Related Deferrals

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

6. Management Audit Costs

The Company is authorized to defer the differences between the rate allowance and its actual costs incurred to retain the consultant to conduct the Commission's Management Audit, with carrying charges at the PTROR, for future recovery or return to customers.

7. Transmission ROW Tree-Trimming Costs

At the end of Rate Year 3, the actual total expenditures for transmission ROW tree trimming will be compared to the sum of the rate allowances for transmission ROW maintenance (a total of $5.042 million) and the cumulative, three-year total of any under-spending will be deferred as of the end of Rate Year 3. 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 succeeding Commission rate order.

8. Listing of Deferrals

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 Signatory Parties recognize that other existing 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 items XIV.E-G of this Proposal.

B. Continuation

The deferrals authorized or permitted consistent with this Proposal will not terminate by reason of the end of Rate Year 3.

C. Right to Petition

The Company may petition the Commission for authorization to defer extraordinary expenditures or revenue loss not otherwise addressed by this Proposal, potentially including items discussed above. Other signatory Parties reserve the right to respond to any such petition as such Signatory Party 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 Period covered by settlement, any Signatory Party hereto may petition the Commission to adjust the Company's rates accordingly.

D. Balance Sheet Offsets

Actual July 1, 2010 balances for the items shown on Appendix F will be offset against each other as of July 1, 2010.

E. Stipulated Rate Allowances

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

F. Reporting of Actual Earnings

The Company will report within 90 days following the end of each Rate Year to the Director of the Office of Accounting and Finance 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, and other exclusions consistent with existing practices, will be excluded in the computations of regulatory rate of return on common equity.

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. 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, C, and D issuances or their successors, will be compared with 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. In the event the 1999 NYSERDA Series B, C, and D issuances are refinanced (including under circumstances not contemplated by the Commission's Order Authorizing Issuance of Securities, issued September 22, 2009, in Case 09-M-0308, and therefore requiring Commission's authorization), the Company is permitted to defer and amortize the costs associated with its new debt, subject to the condition of the above-referenced Order in Case 09-M-0308. In addition, for Rate Years 2 and 3 only, the actual interest rate incurred for new fixed rate debt will be compared with 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 forecast 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 return to customers, with carrying charges at the PTROR.

C. Allowed Rate of Return on Common Equity

The allowed return on common equity is 10.0% for all three Rate Years.

D. Earnings Sharing

Actual regulatory earnings in excess of 10.50% and up to 11.00% will be shared equally between ratepayers and shareholders. Actual regulatory earnings in excess of 11.00% and up to 11.50% will be shared 80/20 (ratepayer/shareholder). Actual regulatory earnings in excess of 11.50% will be shared 90/10 (ratepayer/shareholder). These earnings sharing percentages shall be maintained until the effective date of the succeeding Commission rate order.

The Company will defer for the future benefit of ratepayers fifty percent of its share of any actual earnings in excess of 11.50% to reduce the deferred debit undercollections of MGP Site Investigation & Remediation Costs, interest costs on variable rate, interest costs on new issuances of long term debt, property tax, and stray voltage expense; provided, however, that such reduction in deferred debit deferrals will be further limited so as not to cause the resulting actual earnings to decrease below an 11.50% return on equity.

VII. FORECASTS OF SALES AND CUSTOMERS

Electric and gas forecasts for sales volumes and numbers of customers are set forth in Appendix I.

The electric forecasts utilize Staff’s initial sales and customer forecasts by category, as allocated to service class and/or sub-class utilizing the Company’s sales and customer allocations, and as adjusted utilizing the Company's initial forecast for PV net metering reductions and the Company's rebuttal forecast of EEPS reductions. In addition to the aforementioned adjustments, Staff's concomitant revenue forecast has been adjusted to: (1) reflect base MFC rates only, (2) utilize correct revenue tax factors, and (3) exclude revenue tax on EBC, SBC and RPS.

The gas forecasts utilize both Staff's initial customer forecasts and the Company's rebuttal sales and customer forecasts. For each of the Rate Years, the Company will defer for return to customers through the RDM revenues due to the number of residential customers (SC Nos. 1, 12 & 16) in excess of the lower of the two respective forecasts, but only up to the number of residential customers in the higher of the respective forecasts, with carrying charges at the Other Customer Capital Rate. Revenues calculated using the service classification 1 and 12 UPC targets that are in excess of the higher of the respective residential customer forecasts contained in Appendix I will be retained by the Company. These deferral provisions will also be applicable to the number of non-residential customers (SC Nos. 2, 6, 13 & 15), but only for Rate Year 1. For Rate Years 2 and 3 of this Joint Proposal, only the Company's rebuttal sales and customer forecasts will be used in setting rates for these customers.

Billing determinants corresponding to these adjusted sales are also set forth in Appendix I.

VIII. EMBEDDED COST OF SERVICE

Revised electric Embedded Cost of Service ("ECOS") studies reflecting the Appendix A Income Statement values and the Appendix I customer and sales forecasts for historical embedded electric service, historical embedded delivery-only, and pro-forma delivery-only studies are set forth in Appendix J. Revised gas ECOS studies reflecting the Appendix A Income Statement values and the Appendix I customer and sales forecasts for historical embedded and pro-forma studies are set forth in Appendix K. Both electric and gas ECOS studies also reflect the rate unbundling changes described below.

IX. REVENUE ALLOCATION AND RATE DESIGN

A. Revenue Allocation

If the unitized rates of return for a service class, as determined by both the historic period and pro forma delivery-only ECOS study results set forth in Appendices J and K show a deficiency or surplus, relative to a tolerance band of +/- 15%, that class will receive an allocation of the incremental revenue requirement subject to the following criteria: a maximum of 1.25x overall system increase (in Rate Year 1 only) to classes earning less than 85% of the system average ROR, and a minimum of 0.75x overall system increase to classes earning more than

115% of the system average ROR. If the results of the ECOS indicate varying results in the unitized rate of return for a service class, that class will receive an allocation of the incremental revenue requirement using the overall system average. These criteria produce the following increases for the service classes described below: For electric, SC 3 is allocated 0.75x the system average increase, SC 13 customers are allocated the system average increase, and the allocations for SC 3 and SC 13 are applicable to all three Rate Years. For gas, SC 11 Distribution is allocated the system average increase, SC 11 Transmission customers are allocated 0.75x the system average increase, and the allocations for SC 11 Distribution and SC 11 Transmission are applicable to all three Rate Years. The resulting revenue allocations by class are set forth in Appendix L.

B. Rate Design

Rate design for service classifications other than for electric SC 14 (standby service) and for gas SC 15 (distributed generation - commercial/industrial) and gas SC 16 (distributed generation - residential) is set forth in Appendix M. For each of the sub classes in gas SC 11, the rate increases developed by sub-class pursuant to the revenue allocation procedures set forth in item IX.A above have been levelized across all three Rate Years. Additionally, rates effective July 1, 2013 have been developed for each sub-class under gas SC 11 to reflect the rates that would have been in effect July 1, 2012 if the rate increases had not been levelized. The Company is authorized to defer monthly the revenue differences resulting from the levelization of the rate increases for all gas SC 11 subclasses as compared to the sub-class revenues that would have been received from non-levelized rates for the term of the agreement for future recovery, or return to customers, with carrying charges at the PTROR.

Rate design changes for electric SC 14 (standby service) and for gas SC 15 (distributed generation - commercial/industrial) and gas SC 16 (distributed generation - residential) will be made during the compliance stage of this proceeding.

C. Residential Time of Use – SC6

The Signatory Parties agree that the SC 6 Residential Time of Use on and off-peak volumetric delivery rate split will be phased out, resulting in a single delivery rate in Rate Year 3.

D. Delivery Revenue Increase Bill Impacts

The agreed-upon delivery revenue increases have the estimated bill impacts set forth in Appendix N.

X. Enhanced Powerful Opportunities Program ("EPOP")

The existing Commission-approved EPOP program will be expanded by a targeted incremental 110 participants per Rate

Year. Corresponding incremental funding of $176,000 per Rate Year will be provided and has been reflected in the Appendix A Income Statements. These enhancements will produce total EPOP funding of $1.747 million in Rate Year 1, $1.957 million in Rate Year 2, and $2.170 million in Rate Year 3. 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 applied at the PTROR. The Company will continue to file quarterly and annual reports and evaluations in accordance with the March 22, 2007 EPOP Order in Cases 05-E-0934 and 05-G-0935.

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. Low Income Bill Discount Program

The low income bill discount for the Home Energy Assistance Program ("HEAP") will increase to $7.00 in RY1, $9.00 in RY2, and $11.00 in RY3 and will be applied up to the total corresponding funding in rates at $974,400 in Rate Year 1, $1,252,800 in Rate Year 2, and $1,531,200 in Rate Year 3, 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.

C. Economic Development

Central Hudson shall continue its existing Economic Development programs, as modified in the Economic Development Plan filing made by the Company in September 2009, to the extent that suitable applications are made, and shall implement the additional Economic Development programs, as set forth in the Economic Development Plan filed by the Company in September 2009, to expend up to a total of $1 million per Rate Year from the existing Economic Development funding. Specifically, the Company will continue, as modified, its Shovel Ready program, Job Attraction program, Job Expansion program, Revitalization program, and the Substation Operations and Maintenance Costs program, eliminate the existing Retention and Utility Infrastructure programs, implement a new Wired Innovation Center program and fund the other economic development activities described in its Economic Development Plan filing. In addition, recognizing that the Economic Development fund will be extinguished by the end of Rate Year 3 based upon the programs described above, this Rate Plan includes a $300,000 ED rate allowance beginning in Rate Year 3.

To the extent that the accumulated ED expenditures at the end of Rate Year 3 are less than the combined amount of the existing Economic Development Fund and the Rate Year 3 rate allowance, the Company shall defer such under-spending. The deferred amount will remain allocated for future Economic Development programs and/or purposes.

D. Continuation of Gas Balancing

The treatment of gas balancing will continue per the 2006 Rate Plan.

E. Continuation of ECAM, GSC and PPA Allocation

The existing ECAM and GSC mechanisms and the allocation of Power Purchase Agreement costs/benefits will continue per the 2009 Rate Order.

F. Continuation of Retail Access Lost Revenues

The existing retail access migration-related lost revenue mechanism will continue per the 2009 Rate Order, in which fifty percent of retail access migration related lost revenue is collected through the Supply Charge component of the Merchant

Function Charge, which is avoided by retail access customers, and fifty percent through the transition adjustment paid by all customers.

G. RDMs

1. Electric RDM

The electric RDM Adjustment is applicable to Service Classification Nos. 1, 2, and 6, and those customers taking service under SC No. 14 whose parent service classification would be either SC 1, 2 or 6. The RDM is not applicable to Service Classification Nos. 3, 5, 8, 9 and 13.

a. 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 ending June 30 as set forth in Appendix O.

b. Definitions

1.) Actual Billed Delivery Revenue

Actual Billed Delivery Revenue is defined as the sum of total billed revenue derived from customer charges, base rate energy delivery charges, base rate demand delivery charges and Merchant Function Charges inclusive of lost revenues including the Transition Adjustment, all as applicable. Actual Delivery Revenue shall not include revenues derived from the RDM Adjustment. The actual delivery revenue in the first two months of each rate year will be adjusted upward to reverse the effect of pro-ration between old and new rates in actual revenue. This will be accomplished by multiplying actual billing determinants for each RDM eligible class by the new rate year rates.

2.) Annual RDM Period

Annual RDM Period is defined as the twelve months ending June 30 and each succeeding twelve-month period thereafter.

3.) RDM Adjustment Period

RDM Adjustment Period is defined as the twelve months beginning August 1 immediately following each Annual RDM Period.

c. Determination of RDM Adjustment

For each service classification or sub classification subject to the RDM Adjustment, the Company will, on a monthly basis, compare Actual Billed Delivery Revenue to a Delivery Revenue Target. If the monthly Actual Billed Delivery Revenue exceeds the Delivery Revenue Target, the delivery revenue excess will be accrued for refund to customers at the end of the Annual RDM Period. Likewise, if the monthly Actual Billed Delivery Revenue is less than the Delivery Revenue Target, the delivery revenue shortfall will be accrued for recovery from customers at the end of the Annual RDM Period.

On a monthly basis, interest at the Commission’s rate for other customer provided capital will be calculated on the average of the current and prior month’s cumulative delivery revenue excess/shortfall (net of state and federal income tax benefits).

At the end of an Annual RDM Period, total delivery revenue excess/shortfalls, and associated interest, for each 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. The RDM Adjustment for each applicable service classification or sub classification shall be determined by dividing the amount to be refunded/surcharged to customers in that service classification or sub classification by estimated kWh and/or kW deliveries to customers in that service classification or sub classification over the RDM Adjustment Period. RDM Adjustments shall be rounded to the nearest $0.00001 per kWh or $0.01 per kW.

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.

If for any reason, a service classification or sub classification included in the RDM no longer has customers, the

Company will consult with Commission Staff pursuant to items XIV.E-G of this Proposal.

d. Interim RDM Adjustments

If at any time during an Annual RDM Period, the total of cumulative delivery revenue excess/shortfall for all of the Company's service classifications and sub classifications subject to the RDM Adjustment exceeds $4 million, the Company will implement interim RDM Adjustments by service classification and sub classification on no less than ten days notice. The refund/collection of the Interim RDM Adjustment will occur over a twelve month period. These Interim RDM Adjustments are subject to reconciliation at the end of the Annual RDM Period in which refund/collection of the Interim RDM Adjustment terminates. RDM factors, including Interim RDM Adjustments, may only be changed once in any given six-month period.

e. Statement of RDM Adjustments

Not less than ten (10) days prior to a proposed change in the RDM Adjustments, a Statement showing each factor by service classification, or sub-class, and the effective date will be filed with the Public Service Commission.

f. Continuation

Delivery Revenue Targets for the Annual RDM Period ending June 30, 2013 shall remain in effect until otherwise changed by the Commission.

2. Gas RDM

The unit per customer ("UPC") structure of the gas RDM will continue per the 2009 Rate Order, subject to the deferral of revenues previously described in item VII, above. Specifically, deliveries for Service Classification Nos. 1, 2, 6, 12 and 13 are subject to reconciliation through an RDM Adjustment. The RDM is not applicable to Service Classification Nos. 8, 9, 11, 14, 15 and 16.

Unit per Customer (UPC) Targets set forth in Appendix O are determined for Service Classification Nos. 1 and 12 combined and Service Classification Nos. 2, 6 and 13 combined, by billing block for each month by dividing billing determinant units, Mcf, by customer months based on the billing determinants and customer forecasts as set forth in Appendix I.

Actual UPC will be calculated in the same manner as the target UPC, on a monthly basis, based on actual billed usage as adjusted by the Weather Normalization Adjustment described in General Information Section 27 of the Company's Gas Tariff and billed customer months.

a. Definitions

1.) Annual RDM Period

Annual RDM Period is defined as the twelve months ending June 30 and each succeeding twelve-month period thereafter.

2.) RDM Adjustment Period

RDM Adjustment Period is defined as the twelve months beginning August 1 immediately following each Annual RDM Period.

b. Determination of RDM Adjustment

For each service classification group, the Company will compare, on a monthly basis, the difference between Actual UPC and corresponding UPC Targets, by billing block, to determine the UPC difference. The UPC difference will then be multiplied by the actual number of billed customer months in each service classification group to calculate the total unit difference by billing block. The total unit difference by billing block will then be multiplied by the applicable base delivery rate and the applicable Merchant Function Charges, as defined in General Information Section 42.B of the Company's Gas Tariff, and combined to determine the total delivery revenue excess or shortfall to be accrued for refund to or recovery from customers at the end of the Annual RDM Period.

On a monthly basis, interest at the Commission's rate for other customer provided capital will be calculated on the average of the current and prior month's cumulative delivery revenue excess/shortfall (net of state and federal income tax benefits). At the end of an Annual RDM Period total delivery revenue excess/shortfalls, and associated interest, for each service classification group will be refunded/surcharged to customers through service classification group-specific RDM

Adjustments applicable during a corresponding RDM Adjustment Period. The RDM Adjustment for each applicable service classification group shall be determined by dividing the amount to be refunded/surcharged to customers in that service classification group by estimated Ccf to customers in that service classification group over the RDM Adjustment Period. RDM Adjustments shall be rounded to the nearest $0.00001 per Ccf and applied to all billed Ccf deliveries.

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.
If for any reason, a service classification included in the RDM no longer has customers, the Company will consult with Commission Staff pursuant to items XIV. E-G of this Proposal.

c. Interim RDM Adjustments

If at any time during an Annual RDM Period, the total of the cumulative delivery revenue excess/shortfall exceeds $2 million, the Company will implement interim RDM Adjustments by service classification group on no less than ten days notice. The refund/surcharge of the Interim RDM Adjustment will occur over a twelve-month period. These Interim RDM Adjustments are subject to reconciliation at the end of the Annual RDM Period in which refund/surcharge of the Interim RDM Adjustment terminates. RDM factors, including Interim RDM Adjustments, may only be changed once in any given six-month period.

d. Statement of RDM Adjustments

Not less than ten (10) days prior to a proposed change in the RDM Adjustments, a Statement showing each factor by service classification group and the effective date will be filed with the Public Service Commission.

e. Continuation

UPC Targets for the Annual RDM Period ending June 30, 2013 shall remain in effect until otherwise changed by the Commission.

3. Billing Determinants

RDM billing determinants by Rate Year and by class are set forth in Appendix O.

4. Conforming Tariffs

The electric and gas tariffs will be amended to conform to the provisions set forth in sections 1 and 2, above.

H. Rate Unbundling

The MFCs represent cost-based components of commodity related procurement, commodity related credit and collections, commodity related call center costs, commodity related advertising and promotions, and related Administrative and General (A&G) expenses and rate base items allocated to each component. The MFC will be sub-divided into an MFC Administration and MFC Supply.

MFC Administration will include the commodity related credit and collections component and 50% of commodity related call center costs, plus Administrative and General (A&G) and rate base items associated with each component.

MFC Supply will include commodity related procurement, 50% of the commodity related call center costs, commodity related advertising and promotions, and related A&G expenses and rate base items allocated to each component.

Customers taking commodity service from the Company will be billed MFC Administration and MFC Supply. Customers that choose to purchase their commodity service from an ESCO that is not participating in the POR program will not be billed MFC Administration or MFC Supply. Customers that choose to purchase their commodity service from an ESCO that is participating in the POR program will be billed MFC Administration and avoid MFC Supply.

The MFC structures and related base rates set forth in Appendix M have been modified as follows:

1. All costs recovered in the prior MFC Administration Charge are now be recovered in base rates.

2. A new MFC Administration Charge, comprised of procurement-related credit and collections costs and fifty-percent of procurement-related call center costs, both of which were previously recovered through the MFC Supply Charge, has been established.
3. Delivery-related advertising and promotion costs recovered through prior MFC Supply Charge are now recovered in base delivery rates.
4. The prior MFC Supply Charge will be adjusted by #2 and #3, above.

I. <u>Lost and Unaccounted For and Factors of Adjustment</u>

The gas Lost and Unaccounted For ("LAUF") target and method for annual calculations, as well as the attendant factor of adjustment, will continue as specified on page 59 of the 2009 Rate Order, but will also employ an updated three-year average each Rate Year. The three year average shall be calculated for the twelve months ending August 31 each year, and will be applicable to the period September 1- August 31 of the ensuing year.

Electric service-level specific factors of adjustment will be determined using the most recent 36-month system average and the methodology per the 2009 Rate Order.

J. <u>Hourly Pricing Provision</u>

The Hourly Pricing Provision ("HPP") will be expanded to include customers with demands of 300 kW or greater. The Company will file an implementation plan within two months following Commission approval of this Proposal.

K. Weather Normalization Adjustment

The Weather Normalization Adjustment ("WNA") will be continued per the 2009 Rate Order.

L. Interruptible Imputation

The interruptible imputation structure as set forth in the 2009 Rate Order will be continued and the imputation will be set at $2.4 million for each Rate Year.

XII. PERFORMANCE MECHANISMS

A. Customer Service

The customer service quality performance and reporting requirements will continue per the 2009 Rate Order. In addition, however, the Company shall, within 90 days of Commission approval of this Proposal, file a proposed plan to establish a procedure for benchmarking the results of the IVR-based survey to the results of the current mail survey.

The criteria for the PSC complaint rate and corresponding potential Negative Revenue Adjustments ("NRA") are:

PSC Annual Complaint Rate	Amount
< 1.7	None
1.7	$475,000
1.8	$570,000
1.9	$665,000

2.0	$760,000
2.1	$855,000
2.2	$950,000

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

CSI Annual Performance	Amount
85 or higher	None
84 ≤ CSI < 85	$237,500
83 ≤ CSI < 84	$475,000
82 ≤ CSI < 83	$712,500
< 82	$950,000

B. Electric Reliability

The electric service annual metrics for System Average Frequency Index (SAIFI) and Customer Average Duration Index (CAIDI) shall be a 15 basis point (electric, pre-tax) potential negative revenue adjustment for failure to achieve an annual SAIFI target of 1.45, and a 15 basis point (electric, pre-tax) potential negative revenue adjustment for failure to achieve an annual CAIDI of 2.50. These index targets are the same as approved in the 2009 Rate Order and the Quarterly Meeting process will be continued per the 2009 Rate Order. Also, as in the 2009 Rate Order, the Company will submit an annual compliance report by March 31st for the reliability index targets. All electric metric targets for calendar year 2013 remain in effect until modified by a Commission order in a subsequent Central Hudson electric rate case. The Company will complete the first cycle of the Modified Enhanced distribution ROW tree trimming program by December 31, 2011 or be subject to a five electric basis point (electric, pre-tax) negative revenue adjustment.

C. Gas Safety Metrics

1. Emergency Response Time

The gas emergency response time metrics approved in the 2009 Rate Order will be continued.

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 in the specified calendar year provided, however, that if the Company incurs more costs than provided for in rates, the Company is free to seek deferral for any excess amount expended per page 64 of the 2009 Rate Order above the corresponding rate allowances that are based upon a fixed number of leaks assumed to be repaired and cost per average leak.

Gas	Calendar 2011	2012	2013
Leak Backlog at year end	320	295	260
Repairable leaks at year end	27	24	20

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") set forth in the 2009 Rate order are updated as follows:

Gas	Calendar Year End (per 1000 tickets)		
	2011	2012	2013
Total Damages	2.80	2.60	2.40
Mismarks	0.50	0.50	0.50
CCCD	0.30	0.28	0.25

4. Negative Revenue Adjustments

Should the Company not meet a metric set forth above, it will be subject to the following potential negative Revenue Adjustments: leak backlog - $210,000 (equivalent to 14 gas BP; allocated $90,000 to the Total Leak Backlog target, and $120,000 to the Repairable Leak Backlog target); Excavator damages - $150,000 (equivalent to a total of 10 gas BP; allocated as follows: $30,000 to Total Damages, $60,000 to Mismarks, and $60,000 to CCCD); and Emergency Response - $90,000 (equivalent to 6 gas BP, allocated $60,000 to the 30 Minute Response target, and $30,000 to the 45 Minute Response target).

5. Reporting

The Company will submit a report to the Director of the Office of Electric, Gas and Water on its performance in the areas of the recommended targets within 30 days following the end of the calendar year. The report shall also list, and separately identify, those services replaced under the infrastructure enhancement program and those replaced under the high pressure inside meter set replacement program.

6. Continuation

All gas metric targets for calendar year 2013 remain in effect until modified by a Commission order in a subsequent Central Hudson gas rate case.

7. Infrastructure Enhancement

A minimum capital budget of $19.3 million is established for the replacement of leak-prone pipe over the three-year period of calendar years 2011-2013, subject to expenditure of no less than $6.0 million in each calendar year, ending 12/31/2013. The pipe to be removed from service shall be identified and ranked using a risk-based methodology.

If actual expenditures fall short of $6.0 million in any year, Central Hudson will defer for ratepayer benefit the revenue requirement equivalent of the shortfall multiplied by 0.5.

A minimum capital budget of $2.5 million is established for the installation costs associated with the "Inside Pressure Service Replacement Program" over the three-year period of calendar years 2011-2013, subject to expenditure of no less than $450,000 in calendar year 2011, and $900,000 in each calendar year, 2012 and 2013. The program will be to relocate the meter and service regulator outside the structure, unless it is unsafe to do so, it is limited by local ordinances or historical significance, or when significant individual customer concerns are encountered, provided that the Company is able to obtain satisfactory access to the indoor location of the meter.

If actual expenditures fall short of the $450,000 in calendar year 2011, $900,000 in calendar year 2012 or 2013, Central Hudson will defer for ratepayer benefit the revenue requirement equivalent of the shortfall multiplied by 0.5.

8. Commitment to New Gas Program

During 2010, the Company will initiate a new Gas Construction Quality Assurance Inspection Program for its gas capital construction and its gas leak repair program. The scope of this program is to review and improve overall quality and reduce damages through the inspection of scheduled construction or repair projects being performed by Company, as well as contractor, crews, and to monitor job site safety, adherence to gas construction standards and operation and maintenance procedures. A report of actions taken and lessons learned will be provided annually to Director of the Office of Electric, Gas and Water by March 30 following the end of each calendar year. The Company commits to continue this program and reporting for the term of this Proposal.

XIII. OTHER

The Company will, during the term of this Proposal, continue to file an annual Outreach and Education Plan with the Office of Consumer Policy that is consistent in scope with plans filed by the Company under the 2006 Rate Plan and 2009 Rate Order.

XIV. ADDITIONAL PROVISIONS

A. Submission and Support

The Signatory Parties agree to submit this Proposal to the Commission and recommend that it be adopted and approved by the Commission as the resolution of these cases.

B. Acceptance by the Commission

It is understood that each provision of this Proposal is in consideration and support of all the other provisions and each provision is expressly conditioned upon acceptance by the Commission of this Proposal in its entirety without change. If the Commission does not approve this Proposal according to its terms without change, then the parties to the Proposal will be free to pursue their respective positions in these cases without prejudice.

C. Non-Precedential Nature

The terms and conditions of the Proposal apply solely to, and are binding on each Signatory Party only in the context of, the purposes and results of this Proposal. None of the terms and 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 in any other proceedings before the Commission, or any other regulatory agency, or before any court of law for any purpose except in furtherance of the purposes and results of the Proposal and except as may be necessary in explaining derivation of specific costs or accounting treatments as relevant to future ratemaking proceedings.

D. Reservations

Central Hudson fully reserves its rights concerning its pending petition for rehearing in Cases 08-E-0887 and 08-G-0888. Nothing in this Proposal or the Commission's action in response to it is intended, or may be interpreted, to prejudice Central Hudson's pending petition for rehearing in Cases 08-E-0887 and 08-G-0888. Other Signatory Parties fully reserve their rights to take such positions concerning the petition as they see fit.

E. Mutual Cooperation

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

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

In the event of any disagreement over the interpretation of this Proposal or the implementation of any of the provisions of this Proposal, which cannot be resolved informally among the Signatory 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 within fifteen (15) business days from notification to a Signatory Party or a longer period if agreed to by the Signatory Parties, the matter will be submitted to an ALJ designated by the Chief ALJ for a non-binding determination on an expedited basis using alternative dispute resolution techniques or such other procedures as the ALJ decides are appropriate under the circumstances. Within fifteen (l5) days from the ALJ's decision, any party may petition the Commission for relief from the ALJ's determination on the disputed matter.

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

Notwithstanding the other provisions of this Proposal, the Signatory Parties agree that the following rate changes will be permitted during the effectiveness of this Proposal, provided that the Commission’s approval is granted prior to the implementation of such changes: A minor change in 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 service classifications. The Signatory Parties agree that any Signatory Party 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 Proposal 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 Signatory Parties agree that any Signatory Party 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 Proposal, 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 Signatory Parties recognize that the Commission possesses the authority to act on the level of Central Hudson'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 Proposal 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 of rate design or revenue allocation changes on an overall revenue-neutral basis, including, but not limited to, the implementation of new service classifications and/or cancellation of existing service classifications.

H. Execution in Counterparts

This Proposal is being executed in counterpart originals, and will be binding on each and every Signatory Party when the counterparts have been executed.

WHEREFORE, This Proposal has been agreed to as of the Third day of February, 2010, by and among the following, each of whom, by its signature, represents that he or she is fully authorized to execute this Proposal and, if executing this Proposal in a representative capacity, that he or she is fully authorized to execute it on behalf of his or her principal(s).

_______________________________ Staff of the Department of Public Service

______________________________ Multiple Intervenors

_______________________________ Central Hudson
Gas & Electric Corporation

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 Proposal 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 of rate design or revenue allocation changes on an overall revenue-neutral basis, including, but not limited to, the implementation of new service classifications and/or cancellation of existing service classifications.

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Dated: 02/03/2010

Staff of the Department of Public Service

_________________________________ Multiple Intervenors

_________________________________ Central Hudson
Gas & Electric Corporation

Michael B. Mager

Michael B. Mager, Esq.
Couch White, LLP
Counsel to Multiple Intervenors

Multiple Intervenors

Central Hudson
Gas & Electric Corporation

APPENDICES

Appendix A, Schedule 1

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-05889
Electric Income Statements
($000)

	Rate Years Ending		
	6/30/11	6/30/12	6/30/13
Operating Revenues			
Delivery Revenues - Before Increase	$259,103	$269,581	$277,008
Rate Increase	11,815	9,338	9,054
Other Operating Revenues	8,540	8,627	8,718
Total Operating Revenues	279,458	287,546	294,781
Operating Expenses			
Production Maintenance	223	227	231
Right of Way Maintenance - Transmission	1,651	1,680	1,711
Right of Way Maintenance - Distribution	12,500	12,691	11,397
Labor	46,615	48,255	50,135
Research and Development	2,006	2,006	2,006
Expenses Projected Based on Inflation	9,435	9,599	9,776
Miscellaneous General Expenses	3,471	3,531	3,596
Transportation - Depreciation	1,734	1,806	1,879
Fringe Benefits	5,407	5,523	5,667
Other Post Employee Benefits	5,544	5,544	5,544
Pension Plan	22,974	20,083	16,792
Contract Rents	1,841	1,849	1,855
Uncollectible Accounts	3,837	3,948	4,047
Regulatory Commission Expenses	1,595	1,623	1,653
Information Technology Expense	2,359	2,567	2,730
Other Operating Insurance	1,069	1,088	1,108
Telephone	1,941	1,975	2,011
Legal Services	2,433	2,475	2,521
Special Services	1,299	1,322	1,346
Injuries and Damages	2,075	2,111	2,150
Storm Restoration	4,977	5,064	5,157
Environmental	325	331	337
EPOP and Low Income Bill Discount Program	2,313	2,728	3,146
Expenses Allocated to Affiliates	(745)	(758)	(772)
Stray Voltage Testing	2,250	2,311	2,373
MGP Remediation Cost Recovery	3,778	3,844	3,914
Bill Print & Mail to Customer	536	545	555
Management Audit Costs - 5 year amortization	170	170	170
Economic Development	-	-	255
Transmission Enhanced Infrastructure Maintenance	700	700	700
Productivity & Austerity	(1,260)	(1,245)	(1,228)
Total Operating Expenses	143,053	143,591	142,761
Other Deductions			
Property Taxes	26,232	28,591	31,163
Revenue Taxes	4,344	4,444	4,539
Payroll Taxes	3,491	3,610	3,748
Other Taxes	1,523	1,550	1,578
Depreciation	27,442	28,916	30,359
Total Other Deductions	63,032	67,110	71,387
State Income Taxes	2,950	3,263	3,668
Federal Income Taxes	18,940	19,357	20,172
Total Income Taxes	21,890	22,621	23,840
Total Operating Revenue Deductions	227,975	233,322	237,988
Operating Income	$51,483	$54,224	$56,792
Rate Base	$692,906	$728,821	$764,366
Rate of Return	7.43%	7.44%	7.43%

Appendix A, Schedule 2

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-05889
Gas Income Statements
($000)

	Rate Years Ending		
	6/30/11	6/30/12	6/30/13
Operating Revenues			
Delivery Revenues - Before Increase	64,265	69,492	72,199
Rate Increase	5,709	2,363	1,647
Interruptible Imputation	2,400	2,400	2,400
Other Operating Revenues	1,709	1,661	1,831
Total Operating Revenues	74,084	75,916	78,078
Operating Expenses			
Labor	11,460	11,863	12,325
Research and Development	345	345	345
Expenses Projected Based on Inflation	3,239	3,295	3,356
Miscellaneous General Expenses	682	694	707
Transportation - Depreciation	374	389	405
Fringe Benefits	1,205	1,231	1,263
Other Post Employee Benefits (OPEB)	1,257	1,257	1,257
Pension Plan	5,210	4,555	3,809
Environmental	57	58	59
Contract Rents	145	148	151
Uncollectible Accounts	1,453	1,492	1,533
Regulatory Commission Expenses	485	493	503
Information Technology Expense	430	465	495
Other Operating Insurance	157	160	163
Telephone	300	305	311
Legal Services	566	576	586
Special Services	230	234	238
Injuries and Damages	427	434	442
EPOP and Low Income Bill Discount Program	408	482	555
Expenses Allocated to Affiliates	(132)	(134)	(137)
MGP Remediation Cost Recovery	667	679	691
Bill Print & Mail to Customer	95	97	98
Excess Cost of Removal	820	820	820
Gas Leak Repairs - Distribution Main	1,370	1,394	1,419
Management Audit Costs - 5 year amortization	30	30	30
Economic Development	-	-	45
Productivity & Austerity	(299)	(296)	(293)
Recovery of Net Regulatory Assets	4,554	4,554	4,554
Total Operating Expenses	35,535	35,620	35,732
Other Deductions			
Property Taxes	7,200	7,851	8,561
Revenue Taxes	1,359	1,352	1,377
Payroll Taxes	792	819	850
Other Taxes	197	200	204
Depreciation	7,571	7,883	8,216
Total Other Deductions	17,119	18,105	19,208
State Income Taxes	1,196	1,262	1,335
Federal Income Taxes	6,108	6,308	6,676
Total Income Taxes	7,304	7,570	8,011
Total Operating Revenue Deductions	59,958	61,295	62,951
Operating Income	$14,126	$14,620	$15,128
Rate Base	$190,124	$196,513	$203,599
Rate of Return	7.43%	7.44%	7.43%

Appendix A, Schedule 3

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-05889
Electric Rate Base
($000)

	Electric		
	Rate Years Ending		
	6/30/11	6/30/12	6/30/13
Book Cost of Utility Plant	$1,076,792	$1,133,187	$1,191,241
Less: Accumulated Provision for Depreciation and Amortization	(338,113)	(353,709)	(368,265)
Net Plant	738,679	779,478	822,976
Noninterest-Bearing Construction Work in Progress	33,856	35,310	34,525
Customer Advances for Undergrounding	(1,434)	(1,434)	(1,434)
Deferred Charges	7,695	8,288	8,901
Accumulated Deferred Federal Taxes	(116,343)	(123,020)	(130,305)
Accumulated Deferred State Taxes	(6,506)	(7,559)	(8,727)
Working Capital	37,382	38,181	38,853
Unadjusted Rate Base	693,329	729,244	764,789
Capitalization Adjustment to Rate Base	(423)	(423)	(423)
Total	$692,906	$728,821	$764,366

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-05889
Gas Rate Base
($000)

	Gas		
	Rate Years Ending		
	6/30/11	6/30/12	6/30/13
Book Cost of Utility Plant	$311,390	$324,813	$338,473
Less: Accumulated Provision for Depreciation and Amortization	(105,052)	(110,375)	(115,488)
Net Plant	206,338	214,438	222,985
Noninterest-Bearing Construction Work in Progress	8,581	8,870	9,505
Customer Advances for Undergrounding	(1)	(1)	(1)
Deferred Charges	3,473	3,543	3,577
Accumulated Deferred Federal Taxes	(35,550)	(37,555)	(39,624)
Accumulated Deferred State Taxes	(1,485)	(1,763)	(2,060)
Working Capital	8,894	9,107	9,343
Unadjusted Rate Base	190,250	196,639	203,725
Capitalization Adjustment to Rate Base	(126)	(126)	(126)
Total	$190,124	$196,513	$203,599

Appendix B

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-05889
Net Plant Targets
($000)

	Electric[1]			
	RY1	**RY2**	**RY3**	
Electric Net Plant Targets[2]:				
Plant In Service	1,076,792	1,133,187	1,191,241	
Accumulated Reserve	(338,113)	(353,709)	(368,265)	
Net Plant	738,679	779,478	822,976	
NIBCWIP	33,856	35,310	34,525	
Total Net Plant & NIBCWIP	772,535	814,788	857,501	
Less Transmission Sag Mitigation	-	-	-	**TBD**
Net Electric Plant Targets	772,535	814,788	857,501	
Depreciation Expense Targets:				
Transportation Depreciation [3]	1,734	1,806	1,879	
Depreciation Expense [3]	27,442	28,916	30,359	
Less Transmission Sag Mitigation	-	-	-	**TBD**
Electric Depreciation Expense Target	29,176	30,722	32,238	

	Gas[1]		
	RY1	**RY2**	**RY3**
Gas Net Plant Targets[2]:			
Plant In Service	311,390	324,813	338,473
Accumulated Reserve	(105,052)	(110,375)	(115,488)
Net Plant	206,338	214,438	222,985
NIBCWIP	8,581	8,870	9,505
Net Gas Plant Targets	214,919	223,308	232,490
Depreciation Expense Targets:			
Transportation Depreciation [3]	374	389	405
Depreciation Expense [3]	7,571	7,883	8,216
Gas Depreciation Expense Target	7,945	8,272	8,621

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

Appendix C

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-05889
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	772,535	814,788	857,501	214,919	223,308	232,490
Depreciation Expense	29,176	30,722	32,238	7,945	8,272	8,621
Actual (For Illustrative Purposes Only):						
Total Net Plant & NIBCWIP	766,000	817,000	856,300	214,100	223,400	235,000
Depreciation Expense	29,100	30,800	32,100	7,900	8,290	8,700
Difference (For Illustrative Purposes Only):						
Total Net Plant & NIBCWIP	(6,535)	2,212	(1,201)	(819)	92	2,510
Depreciation Expense	(76)	78	(138)	(45)	18	79
Determination of Revenue Requirements:						
Return Component:						
Net Plant & NIBCWIP Difference	(6,535)	2,212	(1,201)	(819)	92	2,510
x Pre-tax WACC	10.65%	10.66%	10.65%	10.65%	10.66%	10.65%
Return Component	(696)	236	(128)	(87)	10	267
Revenue Requirement on Differences:						
Depreciation	(76)	78	(138)	(45)	18	79
Return Component	(696)	236	(128)	(87)	10	267
Total	(772)	314	(266)	(132)	28	346
Cumulative Revenue Requirement Impact	(772)	(458)	(724)	(132)	(104)	242
Amount Deferred for Customer Benefit - Smaller of Cumulative Amount at End of RY3 or $0[3]			(724)			-

[1] - Electric and Gas amounts include allocation of Common Plant
[2] - See Appendix B
[3] - Negative amounts indicate Regulatory Liabilities due to Customers.

Appendix D: Format for Annual Capital Expenditure Report

The annual reports called for in item IV.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	2009 and Prior	2010	2011	2012	2013	2014	Future	Total	Original Estimate	Projected	Comments
ELECTRIC PRODUCTION														
ELECTRIC TRANSMISSION														
ELECTRIC SUBSTATION														
DISTRIBUTION IMPROVEMENTS														
COMMON PROGRAM														

Notes:

Appendix D

20XX Construction Budget

Budget vs Actual Expenditures
Twelve Months Ended 12/31/XX
($000)

	CURRENT MONTH			YEAR TO DATE				20xx BUDGET			
	Original Budget	December Actual Expend	December % Variation (Act/Bud)	12 Months Budgeted Expend.	12 Months Actual Expend.	Variation	% Budget Expend. (Act/Bud) 12 Months	20xx 12 Months Original Budget	20xx 12 Months Adjusted Budget	12 Months Actual Expend.	% Budget Expend. (Act/Bud) 12 Months
Special Program											
Electric Reliability Improvement Program	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
* Reimbursed by Customer Benefit Fund (1540001 bud)											
Rem OH Facilities - Stewart Terrace	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
* Reimbursed by Customer 1240a-d/1244a-d											
Abandon Gas Mains - Stewart Terrace	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
* Reimbursed by Customer 1245a-d											
Meyers Corners Ckt to Southeast Container	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
* Reimbursed by Southeast Container 7575a-c											
Shenandoah Substation - Capacitor Banks	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
* Reimbursed by Customer 2618-d											
Total Special Program	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Electric Program											
11 Hydro/Gas Turbines	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
12 Transmission	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
13 Substations	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
14 New Business	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
15 Dist. Improvements	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
15 Reliability Improvements	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
16 Transformers	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
17 Meters	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
PS&I	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Total Electric Program	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Gas Program											
21 Propane Plant	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
22 Transmission	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
23 Regulator Stations	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
24 New Business	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
25 Gas Expansion	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
25 Dist. Improvements	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
27 Meters	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
PS&I	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Total Gas Program	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Common Program											
41 Land & Structures	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
42.1 General Office Equip.	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
42.2 EDP Equipment	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
43 Tools & Work Equip.	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
44 Communications	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
45 Transportation	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
PS&I	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Overheads	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
Total Common Program	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
CORPORATE TOTAL (Excl Special Program & Software)	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
4220 **Purchased Software Costs - EDP Equip**	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%
CORPORATE TOTAL (Excl Special Program)	0	0	0.00%	0	0	0	0.00%	0	0	0	0.00%

Major Variation Explanations

Appendix E
Central Hudson Gas & Electric Corporation
Cases 09-E-0588 and 09-G-0589
List of Deferrals

Deferral Item	Deferral Method	Carrying Charges
Asbestos Litigation	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Competition Education Program	Continued deferral of existing funds until funds are exhausted or until the Commission directs the funds to be used for another purpose.	Not applicable
Deferred Temp Metro Transit Bus Tax Surcharge	Deferral of difference between actual expense and amount collected	Not applicable
Deferred Unbilled Gas Revenues	Deferral of the difference between total unbilled and amount recorded in revenue	Not applicable
Deferred Vacation Pay Accrual	Adjusted annually for current accrual	Not applicable
Earnings Sharing	As specified in the JP	Pre-tax Authorized Rate of Return
Economic Development	Deferral of costs under the funding levels specified in the JP	Not applicable
Enhanced Powerful Opportunities Programs	Deferral of costs over / under rate allowance; subject to 15% cap on costs over the rate allowance	Pre-tax Authorized Rate of Return
FAS 109	Adjusted annually for current accrual	Not applicable
FAS 112 Long Term Disability	Adjusted annually for current accrual	Not applicable
Gas Main Replacement Program	Deferral of depreciation expense and carrying charges associated with actual costs spent under the forecasted amount for the rate year	Pre-tax Authorized Rate of Return
Governmental Actions	Deferral of the revenue requirement effect of new governmental actions individually subject to a 2% materiality threshold.	Pre-tax Authorized Rate of Return
Information Technology Expense	Deferral of incremental IT Expense above the rate allowance in RY3 capped at 125K	Pre-tax Authorized Rate of Return
Interest Costs on New Issuances of Long Term Debt	Deferral of costs over / under rate allowance (RY2 & RY3 Only)	Pre-tax Authorized Rate of Return
Interest Costs on Variable Rate Debt	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
International Financial Reporting Standards	Deferral of costs of planning and implementation in RY2 & RY3 capped at a total of $375K	Pre-tax Authorized Rate of Return
Management Audit	Difference between the rate allowance and the costs incurred to retain the consultant to conduct the Commission's Management Audit.	Pre-tax Authorized Rate of Return
MGP Site Investigation and Remediation Costs	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Net Lost Revenues - Merchant Function Charge	Deferral of difference between forecasted and actual lost revenues due to migration for Non-RDM classes	Pre-tax Authorized Rate of Return
Net Plant Targets	As specified in the JP	As specified in the JP
Nine Mile Point 2	Deferral of NEIL insurance credits and associated costs during the term of Joint Proposal.	Pre-tax Authorized Rate of Return
NYS Temporary 18-a Surcharge	Deferral of difference between actual expense and amount collected	Pre-tax Authorized Rate of Return
NYSERDA Series B, C, & D Bonds	Deferral and amortization of the costs associated with its new debt, subject to the condition of the Order in Case 09-M-0308.	Not applicable
OPEB	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Pension Plan	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Property Taxes	90% of the difference between the rate allowance for property tax expense and the actual tax expense subject to limitations as specified in the JP.	Pre-tax Authorized Rate of Return
PSC General Assessment	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return
Purchased Electric Costs	Deferral of difference between actual expense and amount collected	Not applicable
Purchased Gas Costs	Deferral of difference between actual expense and amount collected	Not applicable
Research and Development	Deferral of costs over / under rate allowance	Not applicable
Revenue Decoupling Mechanism - Electric	Deferral of difference between revenues collected and targeted revenues	Other Customer Capital Rate
Revenue Decoupling Mechanism - Gas	Deferral of difference between actual sales and targeted sales	Other Customer Capital Rate
Right of Way Maintenance - Distribution	Deferral of costs under rate allowance cumulatively over Term of JP	Pre-tax Authorized Rate of Return
Right of Way Maintenance - Transmission	Deferral of costs under rate allowance cumulatively over Term of JP	Pre-tax Authorized Rate of Return
RPS and EEPS	Deferral of difference between actual expense and amount collected	Not applicable
Sag Mitigation - Capital Projects	Deferral of depreciation expense and carrying charges associated with actual costs spent over or under the forecasted amount for the rate year	Pre-tax Authorized Rate of Return
SBC - Electric	Deferral of difference between actual expense and amount collected	Not applicable
SBC - Gas	Deferral of difference between actual expense and amount collected	Not applicable
SBC - Gas Low Income Programs	Deferral of difference between actual expense and amount collected	Other Customer Capital Rate
SC 11 - Levelized Rate	As specified in the JP	Pre-tax Authorized Rate of Return
Stray Voltage - Non Mitigation Costs	Deferral of costs under rate allowance	Pre-tax Authorized Rate of Return
Stray Voltage - Mitigation Costs	Deferral of costs over / under rate allowance	Pre-tax Authorized Rate of Return

Appendix F

Central Hudson Gas & Electric Corporation
Case Nos. 09-E-0588 & 09-G-0589
Balance Sheet Offset List

The following accounts are subject to offset as of July 1, 2010:

	Electric	Gas
Pension Costs Over/Under Collection	X	X
Pension Reserve Carrying Charges	X	X
OPEB Costs Over/Under Collection	X	X
OPEB Reserve Carrying Charges	X	X
Unrecovered Regulatory Asset – Non-Interest Bearing		X
Unrecovered Regulatory Asset – Interest Bearing		X
Unrecovered Regulatory Asset – Carrying Charges		X
MGP Site Remediation – Over/Under Collection	X	X
Variable Rate Notes Interest Over/Under Collection	X	X
Long Term Debt – New Issues & Cost Rates	X	X
Research & Development Over/Under Collection	X	X
Long-Term R&D (Millennium Fund) Costs		X
Asbestos Litigation Costs	X	
Asbestos Litigation Carrying Charges	X	
NMP2 Costs	X	
NMP2 Carrying Charges	X	
Excess Electric Depreciation Reserve	X	
Excess Electric Depreciation Reserve Carrying Charges	X	
PSC 18a Temporary Assessment Carrying Charges	X	X
PSC 18a General Assessment Over/Under Collection	X	X
PSC 18a General Assessment Carrying Charges	X	X
Bad Debt Net Write-off – 2008 Deferral		X
Bad Debt Net Write-off – Carrying Charges		X
PV Net Metering	X	
Stray Voltage Testing Over/Under Collection	X	

This listing of items 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 G

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-00589
Revenue Matching Factors

	Rate Year #1	Rate Year #2	Rate Year #3
ELECTRIC:			
Research & Development:			
Rate Allowance ($000)	$2,006	$2,006	$2,006
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	5,342,342	5,304,729	5,253,211
Revenue Matching Factor - $/kWh	$0.000375	$0.000378	$0.000382
Pension Plan:			
Rate Allowance ($000)	$22,974	$20,083	$16,792
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	5,342,342	5,304,729	5,253,211
Revenue Matching Factor - $/kWh	$0.004300	$0.003786	$0.003197
OPEB - Excluding Medicare Credit			
Rate Allowance ($000)	$5,830	$5,830	$5,830
SC 1, 2, 3, 5, 6, 8, 9 & 13 Sales (mWh)	5,342,342	5,304,729	5,253,211
Revenue Matching Factor - $/kWh	$0.001091	$0.001099	$0.001110
OPEB - Medicare Credit			
Rate Allowance ($000)	($286)	($286)	($286)
SC 1, 2, 3, 5, 6, 8, 9, 12 & 13 Sales (mWh)	5,342,342	5,304,729	5,253,211
Revenue Matching Factor - $/kWh	($0.000054)	($0.000054)	($0.000054)
GAS:			
Research & Development:			
Rate Allowance ($000)	$345	$345	$345
SC 1, 2, 6, 12 & 13 Sales (Mcf)	10,412,189	10,353,161	10,445,582
Revenue Matching Factor - $/Mcf	$0.033134	$0.033323	$0.033028
Pension Plan:			
Rate Allowance ($000)	$5,210	$4,555	$3,809
SC 1, 2, 6, 12 & 13 Sales (Mcf)	10,412,189	10,353,161	10,445,582
Revenue Matching Factor - $/Mcf	$0.500375	$0.439962	$0.364652
OPEB - Excluding Medicare Credit			
Rate Allowance ($000)	$1,322	$1,322	$1,322
SC 1, 2, 6, 12 & 13 Sales (Mcf)	10,412,189	10,353,161	10,445,582
Revenue Matching Factor - $/Mcf	$0.126967	$0.127690	$0.126561
OPEB - Medicare Credit			
Rate Allowance ($000)	($65)	($65)	($65)
SC 1, 2, 6, 12 & 13 Sales (Mcf)	10,412,189	10,353,161	10,445,582
Revenue Matching Factor - $/Mcf	($0.006243)	($0.006278)	($0.006223)

Appendix H, Schedule 1

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Capital Structure and Allowed Rate of Return
($000)

Rate Year 1:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 482,898	49.0%	5.10%	2.50%	2.50%
Customer Deposits	8,332	0.9%	2.45%	0.02%	0.02%
Preferred Stock	21,027	2.1%	5.05%	0.11%	0.18%
Common Equity	472,852	48.0%	10.00%	4.80%	7.95%
	$ 985,109	100.0%		7.43%	10.65%

Rate Year 2:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 507,154	49.2%	5.12%	2.52%	2.52%
Customer Deposits	8,332	0.8%	2.45%	0.02%	0.02%
Preferred Stock	21,027	2.0%	5.05%	0.10%	0.17%
Common Equity	495,244	48.0%	10.00%	4.80%	7.95%
	$1,031,757	100.0%		7.44%	10.66%

Rate Year 3:	Amount	Ratio	Cost	Weighted Cost	Pre-Tax Weighted Cost
Long-Term Debt	$ 523,273	49.2%	5.10%	2.51%	2.51%
Customer Deposits	8,332	0.8%	2.45%	0.02%	0.02%
Preferred Stock	21,027	2.0%	5.05%	0.10%	0.17%
Common Equity	510,122	48.0%	10.00%	4.80%	7.95%
	$1,062,754	100.0%		7.43%	10.65%

Central Hudson Gas & Electric Corporation
Average Cost of Long Term Debt
Cases 09-E-0588 and 09-G-0589
For the Rate Year Ending June 30, 2011
$(000)

Outstanding Issues	Maturity Date	Interest Rate %	Principal Amount Outstanding 6/30/2010	Charges During Rate Year	Months Outstanding	Average Amount Outstanding During Rate Year	Interest Expense During Rate Year
1999 NYSERDA Series A Fixed	08/01/27	5.45%	$33,400	-	12	$33,400	$1,820
1999 NYSERDA Series B Variable	07/01/34	2.08%	33,700	-	12	33,700	701
1999 NYSERDA Series C Variable	08/01/28	2.08%	41,150	-	12	41,150	856
1999 NYSERDA Series D Variable	08/01/28	2.08%	41,000	-	12	41,000	853
1998 NYSERDA Series A Fixed	12/01/28	6.50%	16,700	-	12	16,700	1,086
2003 MTN Series D @ 4.33%	09/23/10	4.33%	24,000	(24,000)	3	6,000	260
2002 MTN Series D @ 6.64%	03/28/12	6.64%	36,000	-	12	36,000	2,390
2004 MTN Series D @ 4.73%	02/27/14	4.73%	7,000	-	12	7,000	331
2004 MTN Series E @ 4.80%	11/05/14	4.80%	7,000	-	12	7,000	336
2004 MTN Series E @ 5.05%	11/04/19	5.05%	27,000	-	12	27,000	1,364
2005 MTN Series E @ 5.84%	12/05/35	5.84%	24,000	-	12	24,000	1,402
2006 MTN Series E @ 5.76%	11/17/31	5.76%	27,000	-	12	27,000	1,555
2007 MTN Series F @ 5.80%	03/23/37	5.80%	33,000	-	12	33,000	1,914
2007 MTN Series F @ 6.03%	09/19/17	6.03%	33,000	-	12	33,000	1,990
2008 MTN Series F @ 6.85%	11/01/13	6.85%	30,000	-	12	30,000	2,055
2009 New MTN Issuance	10/01/39	5.80%	24,000	-	12	24,000	1,392
2010 New MTN Issuance *	01/01/30	5.40%	35,048	-	12	35,048	1,893
2010 New MTN Issuance *	09/01/30	5.40%	-	28,500	10	23,750	1,283
2011 New MTN Issuance *	04/01/31	5.40%	-	16,600	3	4,150	224
Average Long Term Debt Outstanding						$482,898	
Interest Charges for the Rate Year							$23,703
Plus: Amortization of Debt Discount and Expense							898
Less: Amortization of Premium on Debt							3
Total Cost of Debt							$24,604
Average Cost Rate of Long Term Debt							5.10%

* 5.40% = average of 10 yr (3.40%) and 30 yr (4.31%) Treasury rates as of November 2009, rounded to 3.85%, plus 155 basis points.

Central Hudson Gas & Electric Corporation
Average Cost of Long Term Debt
Cases 09-E-0588 and 09-G-0589
For the Rate Year Ending June 30, 2012
$(000)

Outstanding Issues	Maturity Date	Interest Rate %	Principal Amount Outstanding 6/30/2009	Charges During Rate Year	Months Outstanding	Average Amount Outstanding During Rate Year	Interest Expense During Rate Year
1999 NYSERDA Series A Fixed	08/01/27	5.45%	$33,400	$0	12	$33,400	$1,820
1999 NYSERDA Series B Variable	07/01/34	2.08%	33,700	-	12	33,700	701
1999 NYSERDA Series C Variable	08/01/28	2.08%	41,150	-	12	41,150	856
1999 NYSERDA Series D Variable	08/01/28	2.08%	41,000	-	12	41,000	853
1998 NYSERDA Series A Fixed	12/01/28	6.50%	16,700	-	12	16,700	1,086
2002 MTN Series D @ 6.64%	03/28/12	6.64%	36,000	(36,000)	9	27,000	1,793
2004 MTN Series D @ 4.73%	02/27/14	4.73%	7,000	-	12	7,000	331
2004 MTN Series E @ 4.80%	11/05/14	4.80%	7,000	-	12	7,000	336
2004 MTN Series E @ 5.05%	11/04/19	5.05%	27,000	-	12	27,000	1,364
2005 MTN Series E @ 5.84%	12/05/35	5.84%	24,000	-	12	24,000	1,402
2006 MTN Series E @ 5.76%	11/17/31	5.76%	27,000	-	12	27,000	1,555
2007 MTN Series F @ 5.80%	03/23/37	5.80%	33,000	-	12	33,000	1,914
2007 MTN Series F @ 6.03%	09/19/17	6.03%	33,000	-	12	33,000	1,990
2008 MTN Series F @ 6.85%	11/01/13	6.85%	30,000	-	12	30,000	2,055
2009 New MTN Issuance	10/01/39	5.80%	24,000	-	12	24,000	1,392
2010 New MTN Issuance	01/01/30	5.40%	35,048	-	12	35,048	1,893
2010 New MTN Issuance	09/01/30	5.40%	28,500	-	12	28,500	1,539
2011 New MTN Issuance	04/01/31	5.40%	16,600	-	12	16,600	896
2011 New MTN Issuance **	07/01/31	5.85%		4,900	12	4,900	287
2012 New MTN Issuance **	03/08/32	5.85%		54,900	4	17,156	1,004
Average Long Term Debt Outstanding						$507,154	
Interest Charges for the Rate Year							25,065
Plus: Amortization of Debt Discount and Expense							904
Less: Amortization of Premium on Debt							3
Total Cost of Debt							$25,972
Average Cost Rate of Long Term Debt							5.12%

** 5.85% = 30 Year Treasury rate as of November 2009 of 4.31% plus 155 basis points, rounded to 5.85%.

Central Hudson Gas & Electric Corporation
Average Cost of Long Term Debt
Cases 09-E-0588 and 09-G-0589
For the Rate Year Ending June 30, 2013
$(000)

Outstanding Issues	Maturity Date	Interest Rate %	Principal Amount Outstanding 6/30/2009	Charges During Rate Year	Months Outstanding	Average Amount Outstanding During Rate Year	Interest Expense During Rate Year
1999 NYSERDA Series A Fixed	08/01/27	5.45%	33,400	0	12	33,400	1,820
1999 NYSERDA Series B Variable	07/01/34	2.08%	33,700	0	12	33,700	701
1999 NYSERDA Series C Variable	08/01/28	2.08%	41,150	0	12	41,150	856
1999 NYSERDA Series D Variable	08/01/28	2.08%	41,000	0	12	41,000	853
1998 NYSERDA Series A Fixed	12/01/28	6.50%	16,700	0	12	16,700	1,086
2004 MTN Series D @ 4.73%	02/27/14	4.73%	7,000	0	12	7,000	331
2004 MTN Series E @ 4.80%	11/05/14	4.80%	7,000	0	12	7,000	336
2004 MTN Series E @ 5.05%	11/04/19	5.05%	27,000	0	12	27,000	1,364
2005 MTN Series E @ 5.84%	12/05/35	5.84%	24,000	0	12	24,000	1,402
2006 MTN Series E @ 5.76%	11/17/31	5.76%	27,000	0	12	27,000	1,555
2007 MTN Series F @ 5.80%	03/23/37	5.80%	33,000	0	12	33,000	1,914
2007 MTN Series F @ 6.03%	09/19/17	6.03%	33,000	0	12	33,000	1,990
2008 MTN Series F @ 6.85%	11/01/13	6.85%	30,000	0	12	30,000	2,055
2009 New MTN Issuance	10/01/39	5.80%	24,000	0	12	24,000	1,392
2010 New MTN Issuance	01/01/30	5.40%	35,048	0	12	35,048	1,893
2010 New MTN Issuance	09/01/30	5.40%	28,500	0	12	28,500	1,539
2011 New MTN Issuance	04/01/31	5.40%	16,600	0	12	16,600	896
2011 New MTN Issuance	07/01/31	5.85%	4,900	0	12	4,900	287
2012 New MTN Issuance	03/08/32	5.85%	54,900	0	12	54,900	3,212
2013 New MTN Issuance ***	04/01/33	5.85%		21,500	3	5,375	314
Average Long Term Debt Outstanding						$523,273	
Interest Charges for the Rate Year							25,795
Plus: Amortization of Debt Discount and Expense							886
Less: Amortization of Premium on Debt							3
Total Cost of Debt							$26,684
Average Cost Rate of Long Term Debt							5.10%

*** 5.85% = 30 Year Treasury rate as of November 2009 of 4.31% plus 155 basis points, rounded to 5.85%.

Appendix H, Schedule 3

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric and Gas Basis Point Values

Basis Point Values:	Electric		
	RY1	**RY2**	**RY2**
Rate Base ($000)	$692,906	$728,821	$764,366
x Equity Ratio	48%	48%	48%
Equity component of Rate Base ($000)	$332,595	$349,834	$366,896
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$33,300	$35,000	$36,700
Pre-tax value of 1 BP - whole dollars	$55,100	$58,000	$60,800

Basis Point Values:	Gas		
	RY1	**RY2**	**RY2**
Rate Base ($000)	$190,124	$196,513	$203,599
x Equity Ratio	48%	48%	48%
Equity component of Rate Base ($000)	$91,259	$94,326	$97,727
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$9,100	$9,400	$9,800
Pre-tax value of 1 BP - whole dollars	$15,100	$15,600	$16,200

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Billing Determinants
(Excludes S.C. Nos. 5 & 8, Unbilled & Interdepartmental)

		Rate Year 1	Rate Year 2	Rate Year 3
S.C. No. 1				
	Customer Months	3,071,952	3,084,720	3,099,150
	kWh	2,059,269,000	2,032,670,000	1,994,580,000
S.C. No. 2 - Non-Demand				
	Customer Months	349,550	350,672	351,949
	kWh	176,048,000	174,847,000	173,449,000
S.C. No. 2 - Secondary				
	Customer Months	148,544	151,848	155,181
	kWh	1,513,733,000	1,506,307,000	1,495,927,000
	kW	4,691,823	4,667,510	4,633,613
S.C. No. 2 - Primary				
	Customer Months	2,068	2,095	2,124
	kWh	253,806,000	252,780,000	252,113,000
	kW	661,397	658,707	657,052
S.C. No. 3				
	Customer Months	388	392	397
	kWh	288,206,000	286,675,000	285,502,000
	kW	660,204	656,718	654,006
	Rkva	71,690	71,332	71,003
S.C. No. 6				
	Customer Months	18,900	18,900	18,900
	On-Peak kWh	9,860,000	9,860,000	9,860,000
	Off-Peak kWh	19,140,000	19,140,000	19,140,000
S.C. No. 9 - Traffic Signals				
	Signal Face Months	72,482	72,482	72,482
	kWh	3,330,000	3,310,000	3,310,000
S.C. No. 13 - Substation				
	Customer Months	84	84	84
	kWh	165,640,000	165,960,000	166,280,000
	kW	304,705	305,202	305,699
	Rkva	47,900	47,900	47,900
S.C. No. 13 - Transmission				
	Customer Months	72	72	72
	kWh	817,460,000	817,460,000	817,460,000
	kW	1,379,438	1,379,438	1,379,438
	Rkva	52,460	51,220	49,620

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Electric Sales (MWh) by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2011)

	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	January 2011	February 2011	March 2011	April 2011	May 2011	June 2011	Total
Service Classification No. 1													
Heating	19,131	19,798	19,302	17,794	20,500	28,930	40,372	43,448	41,251	31,882	23,429	18,060	323,897
EEPS Lost MWh	(388)	(406)	(390)	(364)	(416)	(591)	(1,405)	(1,510)	(1,433)	(1,120)	(815)	(635)	(9,473)
Nonheating	157,155	185,736	176,743	147,375	128,898	143,477	157,217	161,916	142,803	136,127	123,882	132,613	1,793,942
EEPS Lost MWh	(3,128)	(3,692)	(3,512)	(2,931)	(2,565)	(2,860)	(5,354)	(5,531)	(4,869)	(4,641)	(4,218)	(4,517)	(47,818)
PV Lost MWh	(81)	(86)	(88)	(96)	(98)	(106)	(111)	(105)	(121)	(122)	(132)	(133)	(1,279)
	172,689	201,350	192,055	161,778	146,319	168,850	190,719	198,218	177,631	162,126	142,146	145,388	2,059,269
Service Classification No. 2													
Nondemand	14,219	16,462	14,748	14,811	13,107	16,971	16,321	18,663	15,715	15,539	12,712	14,064	183,332
EEPS Lost MWh	(428)	(494)	(442)	(445)	(394)	(509)	(802)	(917)	(773)	(764)	(624)	(692)	(7,284)
Primary	23,515	24,190	21,817	21,872	21,119	21,548	21,877	21,179	21,582	21,415	21,822	22,863	264,799
EEPS Lost MWh	(734)	(755)	(681)	(683)	(660)	(673)	(1,142)	(1,104)	(1,125)	(1,116)	(1,133)	(1,187)	(10,993)
Secondary	144,794	145,893	140,427	125,804	122,755	129,418	133,350	129,658	123,590	124,342	125,116	134,626	1,579,773
EEPS Lost MWh	(4,497)	(4,533)	(4,363)	(3,910)	(3,817)	(4,024)	(7,013)	(6,821)	(6,498)	(6,537)	(6,573)	(7,072)	(65,658)
PV Lost MWh	(24)	(26)	(26)	(29)	(29)	(32)	(33)	(31)	(36)	(37)	(39)	(40)	(382)
	176,845	180,737	171,480	157,420	152,081	162,699	162,558	160,627	152,455	152,842	151,281	162,562	1,943,587
Service Classification No. 3	26,175	27,255	24,928	24,452	24,986	25,946	25,020	23,853	24,088	23,948	24,682	25,345	300,678
EEPS Lost MWh	(818)	(852)	(779)	(764)	(781)	(811)	(1,307)	(1,245)	(1,257)	(1,250)	(1,287)	(1,321)	(12,472)
	25,357	26,403	24,149	23,688	24,205	25,135	23,713	22,608	22,831	22,698	23,395	24,024	288,206
Service Classification No. 5	850	950	1,050	1,210	1,310	1,440	1,360	1,130	1,100	970	870	780	13,020
Service Classification No. 6	2,180	2,480	2,180	2,000	1,860	2,570	2,840	3,360	2,750	2,840	1,940	2,000	29,000
Service Classification No. 8	1,480	1,660	1,830	2,110	2,280	2,510	2,400	2,000	1,940	1,710	1,540	1,370	22,830
Service Classification No. 9	280	280	280	280	280	280	270	270	270	280	280	280	3,330
Service Classification No. 13													
Transmission	77,930	74,900	71,550	70,170	64,240	63,830	64,820	58,000	63,280	67,120	72,920	68,700	817,460
Substation	16,000	15,510	14,370	13,910	13,060	12,760	13,060	12,570	13,400	13,190	13,830	13,980	165,640
	93,930	90,410	85,920	84,080	77,300	76,590	77,880	70,570	76,680	80,310	86,750	82,680	983,100
Interdepartmental	70	90	70	60	60	80	80	120	70	60	60	70	890
Total	473,681	504,360	479,014	432,626	405,695	440,154	461,820	458,903	435,727	423,836	408,262	419,154	5,343,232

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Electric Customers by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2011)

	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	January 2011	February 2011	March 2011	April 2011	May 2011	June 2011	Average
Service Classification No. 1													
Heating	26,313	25,374	26,385	25,317	26,401	25,376	26,474	25,473	26,253	25,666	26,090	25,526	25,887
Nonheating	226,347	232,039	226,284	231,103	230,165	235,153	227,474	232,185	227,785	232,703	227,579	232,487	230,109
	252,660	257,413	252,669	256,420	256,566	260,529	253,948	257,658	254,038	258,369	253,669	258,013	255,996
Service Classification No. 2													
Nondemand	27,829	30,306	27,835	30,211	28,036	31,011	27,581	30,337	27,947	30,373	27,748	30,336	29,129
Primary	170	174	172	173	178	174	168	175	173	173	163	175	172
Secondary	12,297	12,188	12,245	12,281	12,465	12,559	12,215	12,401	12,594	12,372	12,411	12,516	12,379
	40,296	42,668	40,252	42,665	40,679	43,744	39,964	42,913	40,714	42,918	40,322	43,027	41,680
Service Classification No. 3	32	32	32	32	34	32	32	32	32	33	32	33	32
Service Classification No. 5	4,525	4,655	4,545	4,625	4,470	4,536	4,410	4,483	4,694	4,611	4,603	4,594	4,563
Service Classification No. 6	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,575
Service Classification No. 8	207	207	207	207	207	207	207	207	207	207	207	207	207
Service Classification No. 9	297	297	297	297	297	297	297	297	297	297	297	297	297
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	7	7	7	7	7	7	7	7	7	7	7	7	7
	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	299,576	306,891	299,561	305,865	303,812	310,964	300,417	307,209	301,541	308,054	300,689	307,790	304,364

Appendix I Sheet 4 of 14

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Electric Demand Determinants by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2011)

	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	January 2011	February 2011	March 2011	April 2011	May 2011	June 2011	Total
Service Classification No. 2													
Primary kW	61,884	60,979	61,370	58,016	57,860	56,019	50,120	49,349	49,825	57,376	62,842	64,257	689,897
EEPS Lost kW	(1,930)	(1,910)	(1,910)	(1,820)	(1,800)	(1,750)	(2,620)	(2,570)	(2,600)	(2,990)	(3,260)	(3,340)	(28,500)
Secondary kW	434,786	445,949	433,251	419,276	402,298	387,117	370,533	363,624	373,278	401,549	421,544	446,257	4,899,462
EEPS Lost kW	(13,510)	(13,860)	(13,470)	(13,030)	(12,500)	(12,030)	(19,500)	(19,130)	(19,630)	(21,110)	(22,150)	(23,430)	(203,350)
PV Lost kW	(269)	(285)	(301)	(317)	(332)	(349)	(365)	(381)	(397)	(414)	(431)	(448)	(4,289)
	480,961	490,873	478,940	462,125	445,526	429,007	398,168	390,892	400,476	434,411	458,545	483,296	5,353,220
Service Classification No. 3 kW	57,572	60,969	57,991	55,306	61,405	61,184	56,147	54,664	51,619	54,322	58,184	59,351	688,714
EEPS Lost kW	(1,800)	(1,910)	(1,810)	(1,730)	(1,920)	(1,910)	(2,930)	(2,850)	(2,700)	(2,830)	(3,040)	(3,080)	(28,510)
	55,772	59,059	56,181	53,576	59,485	59,274	53,217	51,814	48,919	51,492	55,144	56,271	660,204
Service Classification No. 13													
Transmission kW	125,354	120,284	125,075	115,541	111,033	107,401	102,106	101,511	107,468	118,104	127,550	118,012	1,379,438
Substation kW	28,924	27,379	26,416	25,047	24,838	23,114	23,263	23,958	24,132	25,972	25,600	26,062	304,705
	154,278	147,663	151,491	140,588	135,871	130,515	125,369	125,469	131,600	144,076	153,150	144,074	1,684,143
Total kW	691,011	697,595	686,612	656,289	640,882	618,796	576,754	568,175	580,995	629,979	666,839	683,641	7,697,567
Service Classification No. 3 RkVa	6,931	7,473	7,511	6,815	6,306	4,738	3,941	4,390	5,689	6,817	7,008	7,141	74,760
EEPS Lost RkVa	(230)	(230)	(230)	(220)	(190)	(150)	(200)	(240)	(290)	(360)	(360)	(370)	(3,070)
	6,701	7,243	7,281	6,595	6,116	4,588	3,741	4,150	5,399	6,457	6,648	6,771	71,690
Service Classification No. 13													
Transmission RkVa	3,770	3,950	4,130	3,710	3,660	3,470	3,490	1,820	2,420	2,900	9,500	9,640	52,460
Substation RkVa	4,940	4,320	4,040	3,760	5,700	3,130	3,210	3,290	3,230	3,860	4,010	4,410	47,900
	8,710	8,270	8,170	7,470	9,360	6,600	6,700	5,110	5,650	6,760	13,510	14,050	100,360
Total RkVa	15,411	15,513	15,451	14,065	15,476	11,188	10,441	9,260	11,049	13,217	20,158	20,821	172,050

Appendix I Sheet 5 of 14

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Electric Sales (MWh) by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2012)

	July 2011	August 2011	September 2011	October 2011	November 2011	December 2011	January 2012	February 2012	March 2012	April 2012	May 2012	June 2012	Total
Service Classification No. 1													
Heating	18,858	19,679	19,108	17,704	20,332	28,820	40,171	43,387	41,109	31,834	23,363	18,060	322,425
EEPS Lost MWh	(655)	(691)	(661)	(621)	(707)	(1,009)	(2,093)	(2,257)	(2,138)	(1,675)	(1,216)	(950)	(14,673)
Nonheating	157,654	187,108	178,528	148,631	129,359	143,706	157,630	162,260	142,908	136,622	124,725	133,775	1,802,906
EEPS Lost MWh	(5,372)	(6,365)	(6,073)	(5,058)	(4,405)	(4,899)	(8,033)	(8,294)	(7,291)	(6,970)	(6,355)	(6,819)	(75,934)
PV Lost MWh	(143)	(148)	(149)	(159)	(160)	(171)	(177)	(171)	(188)	(188)	(200)	(200)	(2,054)
	170,342	199,583	190,753	160,497	144,419	166,447	187,498	194,925	174,400	159,623	140,317	143,866	2,032,670
Service Classification No. 2													
Nondemand	14,389	16,663	15,031	15,166	13,344	17,405	16,603	18,926	15,825	15,705	12,879	14,259	186,195
EEPS Lost MWh	(708)	(819)	(739)	(746)	(656)	(854)	(1,203)	(1,371)	(1,147)	(1,138)	(934)	(1,033)	(11,348)
Primary	23,788	24,573	22,173	22,338	21,515	21,991	22,358	21,567	22,109	21,900	22,343	23,376	270,031
EEPS Lost MWh	(1,234)	(1,275)	(1,151)	(1,162)	(1,119)	(1,146)	(1,708)	(1,644)	(1,685)	(1,667)	(1,691)	(1,769)	(17,251)
Secondary	146,565	148,361	142,981	128,881	125,235	132,106	136,329	131,635	126,695	127,172	128,072	137,466	1,611,498
EEPS Lost MWh	(7,695)	(7,793)	(7,509)	(6,769)	(6,582)	(6,943)	(10,617)	(10,255)	(9,862)	(9,898)	(9,962)	(10,692)	(104,577)
PV Lost MWh	(43)	(44)	(44)	(48)	(48)	(51)	(53)	(51)	(56)	(56)	(60)	(60)	(614)
	175,062	179,666	170,742	157,660	151,689	162,508	161,709	158,807	151,879	152,018	150,647	161,547	1,933,934
Service Classification No. 3	26,424	27,623	25,290	24,942	25,435	26,464	25,572	24,281	24,656	24,470	25,238	25,880	306,275
EEPS Lost MWh	(1,378)	(1,441)	(1,318)	(1,300)	(1,327)	(1,381)	(1,955)	(1,854)	(1,880)	(1,870)	(1,924)	(1,972)	(19,600)
	25,046	26,182	23,972	23,642	24,108	25,083	23,617	22,427	22,776	22,600	23,314	23,908	286,675
Service Classification No. 5	840	940	1,040	1,200	1,290	1,430	1,350	1,120	1,090	960	870	770	12,900
Service Classification No. 6	2,180	2,480	2,180	2,000	1,860	2,570	2,840	3,360	2,750	2,840	1,940	2,000	29,000
Service Classification No. 8	1,480	1,650	1,830	2,110	2,280	2,510	2,400	2,000	1,940	1,710	1,540	1,370	22,820
Service Classification No. 9	280	280	280	280	270	270	270	270	270	280	280	280	3,310
Service Classification No. 13													
Transmission	77,930	74,900	71,550	70,170	64,240	63,830	64,820	58,000	63,280	67,120	72,920	68,700	817,460
Substation	16,030	15,540	14,400	13,940	13,080	12,780	13,080	12,590	13,430	13,220	13,860	14,010	165,960
	93,960	90,440	85,950	84,110	77,320	76,610	77,900	70,590	76,710	80,340	86,780	82,710	983,420
Interdepartmental	70	90	70	60	60	80	80	120	70	60	60	70	890
Total	469,260	501,311	476,817	431,559	403,296	437,508	457,664	453,619	431,885	420,431	405,748	416,521	5,305,619

Appendix I Sheet 6 of 14

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Electric Customers by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2012)

	July 2011	August 2011	September 2011	October 2011	November 2011	December 2011	January 2012	February 2012	March 2012	April 2012	May 2012	June 2012	Average
Service Classification No. 1													
Heating	26,218	25,426	26,309	25,354	26,340	25,401	26,424	25,490	26,212	25,675	26,056	25,531	25,870
Nonheating	227,466	233,206	227,373	232,224	231,257	236,257	228,533	233,256	228,833	233,749	228,606	233,524	231,190
	253,684	258,632	253,682	257,578	257,597	261,658	254,957	258,746	255,045	259,424	254,662	259,055	257,060
Service Classification No. 2													
Nondemand	27,916	30,415	27,921	30,316	28,124	31,114	27,666	30,435	28,033	30,469	27,832	30,431	29,223
Primary	172	176	174	176	180	176	170	177	175	176	165	178	175
Secondary	12,568	12,465	12,520	12,557	12,740	12,837	12,490	12,678	12,869	12,648	12,685	12,791	12,654
	40,656	43,056	40,615	43,049	41,044	44,127	40,326	43,290	41,077	43,293	40,682	43,400	42,051
Service Classification No. 3	32	33	32	32	34	32	32	33	33	33	33	33	33
Service Classification No. 5	4,525	4,655	4,545	4,625	4,470	4,536	4,410	4,483	4,694	4,611	4,603	4,594	4,563
Service Classification No. 6	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,575
Service Classification No. 8	207	207	207	207	207	207	207	207	207	207	207	207	207
Service Classification No. 9	297	297	297	297	297	297	297	297	297	297	297	297	297
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	7	7	7	7	7	7	7	7	7	7	7	7	7
	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	300,960	308,499	300,937	307,407	305,208	312,476	301,788	308,675	302,912	309,484	302,043	309,205	305,800

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Electric Demand Determinants by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2012)

	July 2011	August 2011	September 2011	October 2011	November 2011	December 2011	January 2012	February 2012	March 2012	April 2012	May 2012	June 2012	Total
Service Classification No. 2													
Primary kW	62,600	61,942	62,375	59,257	58,948	57,166	51,221	50,251	51,042	58,676	64,343	65,696	703,517
EEPS Lost kW	(3,250)	(3,210)	(3,240)	(3,080)	(3,070)	(2,990)	(3,920)	(3,840)	(3,900)	(4,470)	(4,870)	(4,970)	(44,810)
Secondary kW	440,106	453,487	441,139	429,517	410,415	395,169	378,808	369,163	382,655	410,695	431,503	455,668	4,998,325
EEPS Lost kW	(23,110)	(23,820)	(23,160)	(22,570)	(21,570)	(20,770)	(29,500)	(28,760)	(29,790)	(31,970)	(33,560)	(35,440)	(324,020)
PV Lost kW	(466)	(484)	(501)	(520)	(538)	(556)	(575)	(593)	(612)	(631)	(650)	(669)	(6,795)
	475,880	487,915	476,613	462,604	444,185	428,019	396,034	386,221	399,395	432,300	456,766	480,285	5,326,217
Service Classification No. 3 kW	58,119	61,793	58,831	56,413	62,509	62,402	57,384	55,643	52,837	55,504	59,498	60,605	701,538
EEPS Lost kW	(3,030)	(3,220)	(3,070)	(2,950)	(3,260)	(3,260)	(4,380)	(4,250)	(4,020)	(4,240)	(4,530)	(4,610)	(44,820)
	55,089	58,573	55,761	53,463	59,249	59,142	53,004	51,393	48,817	51,264	54,968	55,995	656,718
Service Classification No. 13													
Transmission kW	125,354	120,284	125,075	115,541	111,033	107,401	102,106	101,511	107,468	118,104	127,550	118,012	1,379,438
Substation kW	28,970	27,424	26,462	25,093	24,868	23,143	23,295	23,991	24,179	26,018	25,647	26,112	305,202
	154,324	147,708	151,537	140,634	135,901	130,544	125,401	125,502	131,647	144,122	153,197	144,124	1,684,640
Total kW	685,293	694,196	683,911	656,701	639,335	617,705	574,439	563,116	579,859	627,686	664,931	680,404	7,667,575
Service Classification No. 3 RkVa	6,999	7,574	7,619	6,952	6,419	4,833	4,028	4,469	5,824	6,966	7,167	7,292	76,142
EEPS Lost RkVa	(360)	(390)	(390)	(360)	(330)	(250)	(310)	(340)	(440)	(530)	(550)	(560)	(4,810)
	6,639	7,184	7,229	6,592	6,089	4,583	3,718	4,129	5,384	6,436	6,617	6,732	71,332
Service Classification No. 13													
Transmission RkVa	3,770	3,950	4,130	3,710	3,660	3,470	3,250	1,590	2,200	2,900	9,230	9,360	51,220
Substation RkVa	4,940	4,320	4,040	3,760	5,700	3,130	3,210	3,290	3,230	3,860	4,010	4,410	47,900
	8,710	8,270	8,170	7,470	9,360	6,600	6,460	4,880	5,430	6,760	13,240	13,770	99,120
Total RkVa	15,349	15,454	15,399	14,062	15,449	11,183	10,178	9,009	10,814	13,196	19,857	20,502	170,452

Appendix I Sheet 8 of 14

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Electric Sales (MWh) by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2013)

	July 2012	August 2012	September 2012	October 2012	November 2012	December 2012	January 2013	February 2013	March 2013	April 2013	May 2013	June 2013	Total
Service Classification No. 1													
Heating	18,878	19,759	19,162	17,734	20,300	28,818	39,872	43,201	40,942	31,689	23,212	17,948	321,515
EEPS Lost MWh	(981)	(1,037)	(992)	(930)	(1,056)	(1,510)	(2,832)	(3,066)	(2,903)	(2,274)	(1,647)	(1,287)	(20,515)
Nonheating	159,475	189,760	181,121	150,395	130,382	144,684	155,316	160,388	141,172	134,911	123,406	133,158	1,804,168
EEPS Lost MWh	(8,130)	(9,657)	(9,218)	(7,657)	(6,644)	(7,382)	(10,790)	(11,174)	(9,818)	(9,383)	(8,572)	(9,251)	(107,676)
PV Lost MWh	(212)	(219)	(218)	(231)	(230)	(244)	(251)	(232)	(263)	(261)	(277)	(274)	(2,912)
	169,030	198,606	189,855	159,311	142,752	164,366	181,315	189,117	169,130	154,682	136,122	140,294	1,994,580
Service Classification No. 2													
Nondemand	14,586	16,887	15,289	15,468	13,573	17,754	16,875	19,200	16,012	15,935	13,099	14,507	189,185
EEPS Lost MWh	(1,055)	(1,223)	(1,107)	(1,121)	(983)	(1,286)	(1,581)	(1,799)	(1,501)	(1,493)	(1,227)	(1,360)	(15,736)
Primary	24,296	25,132	22,689	22,883	22,004	22,475	22,880	22,054	22,673	22,457	22,948	23,996	276,487
EEPS Lost MWh	(1,836)	(1,899)	(1,717)	(1,738)	(1,670)	(1,711)	(2,319)	(2,228)	(2,290)	(2,264)	(2,298)	(2,404)	(24,374)
Secondary	149,321	151,387	146,065	132,006	128,000	134,980	139,474	134,290	129,800	130,205	131,205	140,614	1,647,347
EEPS Lost MWh	(11,608)	(11,774)	(11,355)	(10,264)	(9,957)	(10,504)	(14,742)	(14,183)	(13,704)	(13,748)	(13,859)	(14,852)	(150,550)
PV Lost MWh	(63)	(65)	(65)	(69)	(69)	(73)	(75)	(69)	(79)	(78)	(83)	(82)	(870)
	173,641	178,445	169,799	157,165	150,898	161,635	160,512	157,265	150,911	151,014	149,785	160,419	1,921,489
Service Classification No. 3	26,934	28,186	25,833	25,522	25,987	27,029	26,169	24,819	25,268	25,068	25,885	26,528	313,228
EEPS Lost MWh	(2,055)	(2,151)	(1,969)	(1,945)	(1,983)	(2,065)	(2,656)	(2,511)	(2,549)	(2,540)	(2,619)	(2,683)	(27,726)
	24,879	26,035	23,864	23,577	24,004	24,964	23,513	22,308	22,719	22,528	23,266	23,845	285,502
Service Classification No. 5	830	930	1,030	1,190	1,280	1,410	1,340	1,110	1,080	950	860	760	12,770
Service Classification No. 6	2,180	2,480	2,180	2,000	1,860	2,570	2,840	3,360	2,750	2,840	1,940	2,000	29,000
Service Classification No. 8	1,480	1,650	1,830	2,110	2,280	2,510	2,400	2,000	1,940	1,710	1,540	1,370	22,820
Service Classification No. 9	280	280	280	280	270	270	270	270	270	280	280	280	3,310
Service Classification No. 13													
Transmission	77,930	74,900	71,550	70,170	64,240	63,830	64,820	58,000	63,280	67,120	72,920	68,700	817,460
Substation	16,060	15,570	14,430	13,970	13,100	12,800	13,100	12,610	13,460	13,250	13,890	14,040	166,280
	93,990	90,470	85,980	84,140	77,340	76,630	77,920	70,610	76,740	80,370	86,810	82,740	983,740
Interdepartmental	70	90	70	60	60	80	80	120	70	60	60	70	890
Total	466,380	498,986	474,888	429,833	400,744	434,435	450,190	446,160	425,610	414,434	400,663	411,778	5,254,101

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Electric Customers by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2013)

	July 2012	August 2012	September 2012	October 2012	November 2012	December 2012	January 2013	February 2013	March 2013	April 2013	May 2013	June 2013	Average
Service Classification No. 1													
Heating	26,188	25,427	26,282	25,351	26,316	25,395	26,401	25,481	26,189	25,664	26,033	25,517	25,854
Nonheating	228,503	234,261	228,448	233,321	232,406	237,448	229,742	234,519	230,134	235,122	230,011	234,991	232,409
	254,691	259,688	254,730	258,672	258,722	262,843	256,143	260,000	256,323	260,786	256,044	260,508	258,263
Service Classification No. 2													
Nondemand	28,002	30,512	28,011	30,416	28,219	31,223	27,766	30,550	28,143	30,593	27,950	30,564	29,329
Primary	174	178	177	178	183	178	172	180	178	178	168	180	177
Secondary	12,845	12,741	12,795	12,834	13,015	13,115	12,767	12,957	13,147	12,929	12,965	13,071	12,932
	41,021	43,431	40,983	43,428	41,417	44,516	40,705	43,687	41,468	43,700	41,083	43,815	42,438
Service Classification No. 3	32	33	32	33	35	33	33	33	33	33	33	34	33
Service Classification No. 5	4,525	4,655	4,545	4,625	4,470	4,536	4,410	4,483	4,694	4,611	4,603	4,594	4,563
Service Classification No. 6	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,575
Service Classification No. 8	207	207	207	207	207	207	207	207	207	207	207	207	207
Service Classification No. 9	297	297	297	297	297	297	297	297	297	297	297	297	297
Service Classification No. 13													
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6
Substation	7	7	7	7	7	7	7	7	7	7	7	7	7
	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	302,332	309,930	302,353	308,881	306,707	314,051	303,354	310,326	304,581	311,253	303,826	311,074	307,389

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Electric Demand Determinants by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2013)

	July 2012	August 2012	September 2012	October 2012	November 2012	December 2012	January 2013	February 2013	March 2013	April 2013	May 2013	June 2013	Total
Service Classification No. 2													
Primary kW	63,934	63,351	63,824	60,701	60,288	58,427	52,418	51,386	52,345	60,169	66,084	67,435	720,362
EEPS Lost kW	(4,840)	(4,790)	(4,830)	(4,610)	(4,580)	(4,450)	(5,310)	(5,190)	(5,280)	(6,060)	(6,610)	(6,760)	(63,310)
Secondary kW	448,386	462,742	450,648	439,938	419,481	403,757	387,550	376,617	392,041	420,484	442,066	466,101	5,109,811
EEPS Lost kW	(34,860)	(35,990)	(35,030)	(34,210)	(32,630)	(31,420)	(40,960)	(39,770)	(41,390)	(44,400)	(46,700)	(49,230)	(466,590)
PV Lost kW	(689)	(709)	(729)	(749)	(769)	(790)	(811)	(830)	(851)	(872)	(894)	(915)	(9,608)
	471,931	484,604	473,883	461,070	441,790	425,524	392,887	382,213	396,865	429,321	453,946	476,631	5,290,665
Service Classification No. 3 kW	59,240	63,052	60,094	57,726	63,868	63,735	58,723	56,876	54,148	56,862	61,020	62,122	717,466
EEPS Lost kW	(4,520)	(4,810)	(4,590)	(4,400)	(4,870)	(4,860)	(5,970)	(5,750)	(5,470)	(5,760)	(6,180)	(6,280)	(63,460)
	54,720	58,242	55,504	53,326	58,998	58,875	52,753	51,126	48,678	51,102	54,840	55,842	654,006
Service Classification No. 13													
Transmission kW	125,354	120,284	125,075	115,541	111,033	107,401	102,106	101,511	107,468	118,104	127,550	118,012	1,379,438
Substation kW	29,015	27,469	26,508	25,139	24,898	23,173	23,327	24,024	24,226	26,065	25,694	26,161	305,699
	154,369	147,753	151,583	140,680	135,931	130,574	125,433	125,535	131,694	144,169	153,244	144,173	1,685,137
Total kW	681,020	690,599	680,970	655,076	636,719	614,973	571,073	558,874	577,237	624,592	662,030	676,646	7,629,808
Service Classification No. 3 RkVa	7,133	7,728	7,784	7,113	6,558	4,936	4,123	4,568	5,968	7,136	7,350	7,476	77,873
EEPS Lost RkVa	(540)	(590)	(600)	(540)	(510)	(380)	(420)	(470)	(600)	(720)	(750)	(750)	(6,870)
	6,593	7,138	7,184	6,573	6,048	4,556	3,703	4,098	5,368	6,416	6,600	6,726	71,003
Service Classification No. 13													
Transmission RkVa	3,510	3,650	3,850	3,450	3,430	3,200	3,250	1,590	2,200	2,900	9,230	9,360	49,620
Substation RkVa	4,940	4,320	4,040	3,760	5,700	3,130	3,210	3,290	3,230	3,860	4,010	4,410	47,900
	8,450	7,970	7,890	7,210	9,130	6,330	6,460	4,880	5,430	6,760	13,240	13,770	97,520
Total RkVa	15,043	15,108	15,074	13,783	15,178	10,886	10,163	8,978	10,798	13,176	19,840	20,496	168,523

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Gas Billing Determinants
(Excludes Unbilled)

		Rate Year 1	Rate Year 2	Rate Year 3
S.C. No. 1 & 12 Res. Heat	Block 1 - Customer Months	661,772	666,080	672,700
	Block 1 - Mcf - Included in Customer Charge	129,387	126,208	124,667
	Block 2 - Mcf	2,172,788	2,118,595	2,094,244
	Block 3 - Mcf	2,410,332	2,349,894	2,324,707
S.C. No. 1 & 12 Res. Non-Heat	Block 1 - Customer Months	105,630	102,104	98,579
	Block 1 - Mcf - Included in Customer Charge	17,521	16,727	16,110
	Block 2 - Mcf	103,683	99,126	95,520
	Block 3 - Mcf	57,397	54,897	52,812
S.C. No. 2, 6 & 13 Heat	Block 1 - Customer Months	109,789	113,641	118,644
	Block 1 - Mcf - Included in Customer Charge	18,112	18,387	18,960
	Block 2 - Mcf	615,780	625,116	644,970
	Block 3 - Mcf	3,333,850	3,383,753	3,489,420
	Block 4 - Mcf	810,134	821,914	847,241
S.C. No. 2, 6 & 13 Non-Heat	Block 1 - Customer Months	15,104	15,082	15,063
	Block 1 - Mcf - Included in Customer Charge	2,605	2,575	2,580
	Block 2 - Mcf	74,934	74,453	74,270
	Block 3 - Mcf	309,903	307,913	307,180
	Block 4 - Mcf	355,763	353,603	352,901
S.C. No. 11 Transmission	Customer Months	36	36	36
	MDQ	162,240	162,240	162,240
S.C. No. 11 Distribution	Customer Months	12	12	12
	MDQ	4,236	4,236	4,236
S.C. No. 11 - DLM	Customer Months	12	12	12
	MDQ	69,996	69,996	69,996
Interdepartmental (S.C. No. 2)	Block 4 - Mcf	23,430	23,430	23,430

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Gas Customers & Sales by Service Classification
Rate Year 1 (Twelve Months Ended June 30, 2011)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	121,353	110,796	91,951	132,452	242,048	567,515	719,707	964,701	777,169	689,096	373,566	228,823	5,019,177
Nonheating	8,239	7,447	6,775	8,958	10,758	19,240	20,274	26,950	21,784	22,580	12,889	12,707	178,601
Case 07-M-0548 EEPS Adjustment	(5,570)	(5,080)	(4,220)	(6,080)	(11,100)	(26,000)	(47,670)	(63,900)	(51,500)	(45,650)	(24,740)	(15,160)	(306,670)
	124,022	113,163	94,506	135,330	241,706	560,755	692,311	927,751	747,453	666,026	361,715	226,370	4,891,108
Service Classification Nos. 2, 6 & 13													
Heat	143,620	124,885	137,000	179,061	342,708	593,005	780,769	827,120	685,339	492,122	301,411	170,836	4,777,876
Nonheating	42,319	44,017	43,000	52,332	58,046	77,912	84,459	88,297	77,222	71,491	52,000	52,110	743,205
	185,939	168,902	180,000	231,393	400,754	670,917	865,228	915,417	762,561	563,613	353,411	222,946	5,521,081
Service Classification No. 8	8,200	10,600	9,730	38,900	45,620	74,810	88,350	74,910	67,940	35,430	13,610	9,800	477,900
Service Classification No. 9	61,880	62,440	60,260	99,840	121,940	180,230	128,890	131,910	160,130	105,520	63,220	57,370	1,233,630
Service Classification No. 11	108,541	104,406	73,364	130,439	182,727	279,852	274,721	293,870	225,879	171,474	127,290	100,820	2,073,383
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	80	70	70	230	1,760	3,990	4,670	5,110	3,900	2,500	860	190	23,430
Total Sales & Transport	488,662	459,581	417,930	636,132	994,507	1,770,554	2,054,170	2,348,968	1,967,863	1,544,563	920,106	617,496	14,220,532
Customers													
Service Classification Nos. 1 & 12													
Heat	51,862	57,997	51,939	58,060	52,007	58,124	52,067	58,189	52,770	58,244	52,202	58,311	55,148
Nonheating	8,077	9,721	7,880	9,695	7,855	9,658	8,168	9,786	7,910	9,593	7,757	9,530	8,803
	59,939	67,718	59,819	67,755	59,862	67,782	60,235	67,975	60,680	67,837	59,959	67,841	63,950
Service Classification Nos. 2, 6 & 13													
Heat	8,600	9,307	8,618	9,527	8,651	9,573	8,952	9,594	8,902	9,639	8,761	9,665	9,149
Nonheating	1,124	1,371	1,129	1,381	1,120	1,408	1,145	1,390	1,145	1,388	1,124	1,379	1,259
	9,724	10,678	9,747	10,908	9,771	10,981	10,097	10,984	10,047	11,027	9,885	11,044	10,408
Service Classification No. 8	32	32	32	32	32	32	32	32	32	32	32	32	32
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	69,696	78,429	69,599	78,696	69,666	78,796	70,365	78,992	70,760	78,897	69,877	78,918	74,391

Appendix I Sheet 13 of 14

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Gas Customers & Sales by Service Classification
Rate Year 2 (Twelve Months Ended June 30, 2012)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	121,223	110,937	92,098	131,535	239,571	563,972	715,722	960,461	775,335	687,313	372,804	228,466	4,999,437
Nonheating	7,656	7,110	6,398	8,756	10,401	18,412	19,360	25,763	20,747	21,450	12,604	12,093	170,750
Case 07-M-0548 EEPS Adjustment	(8,040)	(7,350)	(6,100)	(8,720)	(15,870)	(37,340)	(61,480)	(82,510)	(66,630)	(59,050)	(32,020)	(19,630)	(404,740)
	120,839	110,697	92,396	131,571	234,102	545,044	673,602	903,714	729,452	649,713	353,388	220,929	4,765,447
Service Classification Nos. 2, 6 & 13													
Heat	144,920	126,705	139,349	179,428	344,921	597,318	792,101	839,040	698,424	501,550	309,924	175,490	4,849,170
Nonheating	42,128	43,853	42,848	51,965	57,556	77,240	83,792	87,614	76,666	71,113	51,776	51,993	738,544
	187,048	170,558	182,197	231,393	402,477	674,558	875,893	926,654	775,090	572,663	361,700	227,483	5,587,714
Service Classification No. 8	8,200	10,600	9,730	38,900	45,620	74,810	88,350	74,910	67,940	35,430	13,610	9,800	477,900
Service Classification No. 9	61,880	62,440	60,260	99,840	121,940	180,230	128,890	131,910	160,130	105,520	63,220	57,370	1,233,630
Service Classification No. 11	108,541	104,406	73,364	130,439	182,727	279,852	274,721	293,870	225,879	171,474	127,290	100,820	2,073,383
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	80	70	70	230	1,760	3,990	4,670	5,110	3,900	2,500	860	190	23,430
Total Sales & Transport	486,588	458,771	418,017	632,373	988,626	1,758,484	2,046,126	2,336,168	1,962,391	1,537,300	920,068	616,592	14,161,504

Customers	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	52,253	58,376	52,318	58,427	52,374	58,479	52,421	58,532	53,114	58,587	52,533	58,666	55,507
Nonheating	7,811	9,401	7,619	9,374	7,594	9,336	7,895	9,458	7,644	9,270	7,495	9,207	8,509
	60,064	67,777	59,937	67,801	59,968	67,815	60,316	67,990	60,758	67,857	60,028	67,873	64,015
Service Classification Nos. 2, 6 & 13													
Heat	8,814	9,547	8,874	9,803	8,946	9,886	9,284	9,945	9,270	10,027	9,167	10,078	9,470
Nonheating	1,122	1,369	1,127	1,379	1,118	1,407	1,142	1,389	1,143	1,386	1,123	1,377	1,257
	9,936	10,916	10,001	11,182	10,064	11,293	10,426	11,334	10,413	11,413	10,290	11,455	10,727
Service Classification No. 8	32	32	32	32	32	32	32	32	32	32	32	32	32
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	70,033	78,726	69,971	79,016	70,065	79,141	70,775	79,357	71,204	79,303	70,351	79,361	74,775

Appendix I Sheet 14 of 14

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Gas Customers & Sales by Service Classification
Rate Year 3 (Twelve Months Ended June 30, 2013)

Sales & Transport (Mcf)	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	121,554	111,658	92,832	131,965	241,331	567,970	723,535	970,442	784,181	695,417	377,965	231,938	5,050,788
Nonheating	7,245	6,869	6,180	8,548	10,116	17,778	18,690	24,780	19,805	20,525	12,236	11,670	164,442
Case 07-M-0548 EEPS Adjustment	(10,450)	(9,600)	(7,980)	(11,340)	(20,730)	(48,780)	(76,160)	(102,150)	(82,580)	(73,210)	(39,780)	(24,410)	(507,170)
	118,349	108,927	91,032	129,173	230,717	536,968	666,065	893,072	721,406	642,732	350,421	219,198	4,708,060
Service Classification Nos. 2, 6 & 13													
Heat	150,826	131,894	145,254	184,715	356,090	614,164	816,941	863,156	720,113	515,891	320,566	180,981	5,000,591
Nonheating	42,077	43,858	42,814	51,880	57,372	77,047	83,589	87,278	76,413	70,952	51,701	51,950	736,931
	192,903	175,752	188,068	236,595	413,462	691,211	900,530	950,434	796,526	586,843	372,267	232,931	5,737,522
Service Classification No. 8	8,200	10,600	9,730	38,900	45,620	74,810	88,350	74,910	67,940	35,430	13,610	9,800	477,900
Service Classification No. 9	61,880	62,440	60,260	99,840	121,940	180,230	128,890	131,910	160,130	105,520	63,220	57,370	1,233,630
Service Classification No. 11	108,541	104,406	73,364	130,439	182,727	279,852	274,721	293,870	225,879	171,474	127,290	100,820	2,073,383
Service Classification No. 14	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
Interdepartmental	80	70	70	230	1,760	3,990	4,670	5,110	3,900	2,500	860	190	23,430
Total Sales & Transport	489,953	462,195	422,524	635,177	996,226	1,767,061	2,063,226	2,349,306	1,975,781	1,544,499	927,668	620,309	14,253,925

Customers	July	August	September	October	November	December	January	February	March	April	May	June	Total
Service Classification Nos. 1 & 12													
Heat	52,621	58,755	52,732	58,878	52,873	59,014	52,992	59,138	53,756	59,277	53,260	59,404	56,058
Nonheating	7,546	9,080	7,359	9,053	7,333	9,014	7,622	9,130	7,378	8,947	7,233	8,884	8,215
	60,167	67,835	60,091	67,931	60,206	68,028	60,614	68,268	61,134	68,224	60,493	68,288	64,273
Service Classification Nos. 2, 6 & 13													
Heat	9,237	9,976	9,302	10,227	9,368	10,307	9,701	10,360	9,682	10,437	9,573	10,474	9,887
Nonheating	1,121	1,367	1,125	1,377	1,117	1,405	1,142	1,386	1,142	1,384	1,122	1,375	1,255
	10,358	11,343	10,427	11,604	10,485	11,712	10,843	11,746	10,824	11,821	10,695	11,849	11,142
Service Classification No. 8	32	32	32	32	32	32	32	32	32	32	32	32	32
Interdepartmental	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Sales & Transport Customers	70,558	79,211	70,551	79,568	70,724	79,773	71,490	80,047	71,991	80,078	71,221	80,170	75,449

Appendix J, Schedule A
Electric Cost of Service
Electric Department 2007 Rate of Return Statement

			Residential			Small General Service			Large General Service			SC5 Area	SC8 Street	SC9 Traffic
	Rate Base:	Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
1	Gross Plant in Service	$ 841,316,671	$ 489,299,794	$ 67,516,914	$ 6,442,141	$ 59,079,985	$ 122,775,599	$ 13,229,896	$ 18,153,717	$ 8,604,783	$ 34,783,745	$ 9,451,981	$ 11,516,713	$ 461,404
2	less: Accum. Provisions for Depr. & Amort.	$ 259,703,270	$ 148,086,769	$ 20,545,534	$ 1,981,073	$ 17,791,314	$ 39,612,927	$ 4,372,811	$ 6,025,007	$ 2,845,644	$ 12,084,618	$ 2,746,088	$ 3,471,071	$ 140,414
3	Net Plant in Service	$ 581,613,401	$ 341,213,024	$ 46,971,380	$ 4,461,068	$ 41,288,671	$ 83,162,671	$ 8,857,085	$ 12,128,710	$ 5,759,140	$ 22,699,127	$ 6,705,893	$ 8,045,642	$ 320,990
4	plus: Construction Work in Progress	$ 32,990,000	$ 19,224,127	$ 2,661,621	$ 254,315	$ 2,294,942	$ 4,738,772	$ 519,969	$ 721,777	$ 347,067	$ 1,401,195	$ 382,015	$ 426,233	$ 17,967
5	plus: Working Capital	$ 32,389,000	$ 18,843,955	$ 2,541,710	$ 239,099	$ 2,374,006	$ 5,023,026	$ 490,506	$ 636,342	$ 258,716	$ 1,109,023	$ 307,165	$ 545,240	$ 20,210
6	less: Accumulated Deferred Income Taxes	$ 75,995,000	$ 42,621,022	$ 5,914,204	$ 580,291	$ 5,126,128	$ 11,772,966	$ 1,386,213	$ 1,911,664	$ 904,739	$ 3,831,431	$ 819,150	$ 1,086,912	$ 40,281
7	plus: Deferred Charges	$ (40,844,000)	$ (23,909,916)	$ (3,304,963)	$ (315,380)	$ (2,857,829)	$ (5,811,328)	$ (633,430)	$ (878,071)	$ (421,682)	$ (1,679,320)	$ (477,581)	$ (532,257)	$ (22,241)
8	less: Other Rate Base Deductions	$ (7,380,000)	$ (4,234,231)	$ (589,454)	$ (57,225)	$ (512,330)	$ (1,109,355)	$ (118,685)	$ (162,318)	$ (79,986)	$ (312,715)	$ (84,005)	$ (115,877)	$ (3,819)
9	Total Rate Base	$ 537,533,401	$ 316,984,400	$ 43,544,998	$ 4,116,035	$ 38,485,993	$ 76,449,531	$ 7,966,601	$ 10,859,413	$ 5,118,489	$ 20,011,310	$ 6,182,347	$ 7,513,823	$ 300,463
	Revenues:													
10	Electric Delivery Revenues	$ 575,273,377	$ 249,924,255	$ 42,410,839	$ 4,381,978	$ 22,696,503	$ 142,492,954	$ 15,388,300	$ 20,758,588	$ 1,733,686	$ 68,259,412	$ 1,920,627	$ 4,868,264	$ 437,970
11	Other Revenues	$ 41,580,840	$ 17,573,331	$ 2,897,447	$ 293,767	$ 1,602,364	$ 9,492,155	$ 1,107,947	$ 1,636,885	$ 732,631	$ 5,552,620	$ 324,992	$ 339,912	$ 26,788
12	Total Operating Revenues	$ 616,854,217	$ 267,497,587	$ 45,308,286	$ 4,675,745	$ 24,298,868	$ 151,985,109	$ 16,496,246	$ 22,395,473	$ 2,466,317	$ 73,812,032	$ 2,245,619	$ 5,208,176	$ 464,759
	Expenses:													
13	Operation and Maintenance	$ 510,766,394	$ 219,695,755	$ 35,940,300	$ 3,621,557	$ 23,798,230	$ 120,792,545	$ 13,969,369	$ 17,878,266	$ 1,141,934	$ 67,495,351	$ 1,960,380	$ 4,126,951	$ 345,757
14	Depreciation and Amortization	$ 22,251,467	$ 13,003,591	$ 1,790,157	$ 170,089	$ 1,579,897	$ 3,220,683	$ 341,819	$ 466,289	$ 220,714	$ 878,254	$ 252,627	$ 315,045	$ 12,301
15	Taxes Other than Income	$ 27,063,824	$ 12,745,852	$ 1,701,251	$ 200,288	$ 1,338,511	$ 5,879,139	$ 744,476	$ 1,076,630	$ 424,564	$ 2,730,913	$ 61,132	$ 148,654	$ 12,415
16	Federal Income Tax	$ 13,755,420	$ 4,544,586	$ 1,528,759	$ 184,963	$ (1,070,028)	$ 6,333,112	$ 390,827	$ 859,604	$ 182,123	$ 705,850	$ (50,741)	$ 118,868	$ 27,496
17	NYS Income Tax	$ 3,243,229	$ 1,071,711	$ 352,518	$ 42,520	$ (236,407)	$ 1,490,434	$ 92,354	$ 198,879	$ 41,765	$ 162,927	$ (14,137)	$ 34,264	$ 6,402
18	Total Operating Expenses	$ 577,080,333	$ 251,061,495	$ 41,312,985	$ 4,219,417	$ 25,410,203	$ 137,715,912	$ 15,538,845	$ 20,479,669	$ 2,011,099	$ 71,973,293	$ 2,209,261	$ 4,743,782	$ 404,372
19	Net Operating Income (line12 less line 18)	$ 39,773,884	$ 16,436,092	$ 3,995,301	$ 456,327	$ (1,111,335)	$ 14,269,197	$ 957,401	$ 1,915,804	$ 455,218	$ 1,838,739	$ 36,359	$ 464,394	$ 60,387
20	Rate of Return (line 19 divided by line 9)	7.40%	5.19%	9.18%	11.09%	-2.89%	18.66%	12.02%	17.64%	8.89%	9.19%	0.59%	6.18%	20.10%
21	Index (Class ROR divided by System ROR)	100	70	124	150	(39)	252	162	238	120	124	8	84	272

Appendix J, Schedule B
Electric Cost of Service
Electric Department RY #1 Rate of Return Statement

			Residential			Small General Service			Large General Service			SC5 Area	SC8 Street	SC9 Traffic
	Rate Base:	Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
1	Gross Plant in Service	$ 1,034,292,000	$ 598,015,491	$ 81,499,312	$ 6,804,746	$ 71,414,395	$ 159,588,820	$ 19,614,796	$ 21,274,002	$ 10,974,001	$ 39,798,364	$ 11,011,553	$ 13,761,146	$ 535,376
2	less: Accum. Provisions for Depr. & Amort.	$ 295,615,067	$ 168,971,112	$ 23,111,617	$ 1,939,348	$ 20,183,826	$ 46,937,886	$ 5,826,671	$ 6,320,549	$ 3,248,488	$ 12,046,617	$ 2,997,974	$ 3,878,719	$ 152,258
3	Net Plant in Service	$ 738,676,933	$ 429,044,378	$ 58,387,695	$ 4,865,398	$ 51,230,569	$ 112,650,934	$ 13,788,125	$ 14,953,453	$ 7,725,513	$ 27,751,747	$ 8,013,579	$ 9,882,427	$ 383,117
4	plus: Construction Work in Progress	$ 33,856,000	$ 19,607,047	$ 2,681,587	$ 224,409	$ 2,313,789	$ 5,157,144	$ 644,801	$ 705,472	$ 368,830	$ 1,337,183	$ 372,955	$ 425,270	$ 17,512
5	plus: Working Capital	$ 37,382,000	$ 21,883,467	$ 2,898,448	$ 235,900	$ 2,742,752	$ 5,855,473	$ 656,527	$ 677,245	$ 313,949	$ 1,138,958	$ 345,499	$ 612,815	$ 20,967
6	less: Accumulated Deferred Income Taxes	$ 122,849,000	$ 69,071,339	$ 9,449,669	$ 807,792	$ 8,259,522	$ 19,857,198	$ 2,621,855	$ 2,845,366	$ 1,463,722	$ 5,421,536	$ 1,264,870	$ 1,724,017	$ 62,115
7	plus: Deferred Charges	$ 7,695,000	$ 4,420,129	$ 605,698	$ 51,007	$ 519,414	$ 1,196,436	$ 151,549	$ 166,165	$ 86,328	$ 318,345	$ 82,131	$ 93,848	$ 3,949
8	less: Other Rate Base Deductions	$ 1,857,000	$ 1,260,024	$ 159,358	$ 11,142	$ 153,670	$ 187,705	$ 17,029	$ 17,593	$ 4,290	$ 15,329	$ 21,652	$ 7,836	$ 1,374
9	Total Rate Base	$ 692,903,933	$ 404,623,659	$ 54,964,401	$ 4,557,780	$ 48,393,332	$ 104,815,084	$ 12,602,118	$ 13,639,376	$ 7,026,608	$ 25,109,368	$ 7,527,642	$ 9,282,507	$ 362,058
	Revenues:													
10	Electric Delivery Revenues	$ 259,100,075	$ 145,209,352	$ 22,728,711	$ 1,786,035	$ 12,514,260	$ 53,579,821	$ 4,860,133	$ 5,874,823	$ 2,003,905	$ 4,719,706	$ 1,328,283	$ 4,292,677	$ 202,369
11	Other Revenues	$ 8,369,485	$ 4,138,911	$ 844,471	$ 54,161	$ 353,077	$ 875,215	$ 59,276	$ 72,034	$ 118,447	$ 1,645,395	$ 205,274	$ 1,210	$ 2,012
12	Total Operating Revenues	$ 267,469,560	$ 149,348,264	$ 23,573,182	$ 1,840,197	$ 12,867,337	$ 54,455,036	$ 4,919,409	$ 5,946,858	$ 2,122,352	$ 6,365,101	$ 1,533,557	$ 4,293,887	$ 204,381
	Expenses:													
13	Operation and Maintenance	$ 142,889,000	$ 83,957,367	$ 10,833,083	$ 860,293	$ 11,045,602	$ 23,196,503	$ 2,378,663	$ 2,311,346	$ 922,012	$ 3,418,985	$ 1,076,634	$ 2,802,809	$ 85,702
14	Depreciation and Amortization	$ 27,442,000	$ 16,084,733	$ 2,189,328	$ 181,264	$ 1,921,416	$ 4,071,961	$ 493,474	$ 535,280	$ 280,607	$ 987,089	$ 311,569	$ 370,921	$ 14,357
15	Taxes Other than Income	$ 35,301,000	$ 17,129,976	$ 2,245,492	$ 229,867	$ 1,775,902	$ 7,957,126	$ 1,111,404	$ 1,272,844	$ 578,594	$ 2,694,238	$ 69,699	$ 220,627	$ 15,233
16	Federal Income Tax	$ 15,167,870	$ 7,604,237	$ 2,319,742	$ 152,824	$ (963,858)	$ 5,486,994	$ 212,912	$ 499,638	$ 62,164	$ (419,805)	$ (26,803)	$ 213,220	$ 26,605
17	NYS Income Tax	$ 2,151,932	$ 1,028,430	$ 397,656	$ 24,881	$ (253,841)	$ 967,938	$ 22,616	$ 77,764	$ (642)	$ (137,703)	$ (16,308)	$ 36,252	$ 4,891
18	Total Operating Expenses	$ 222,951,802	$ 125,804,743	$ 17,985,302	$ 1,449,129	$ 13,525,221	$ 41,680,522	$ 4,219,069	$ 4,696,871	$ 1,842,734	$ 6,542,804	$ 1,414,791	$ 3,643,828	$ 146,788
19	Net Operating Income (line12 less line 18)	$ 44,517,758	$ 23,543,520	$ 5,587,880	$ 391,068	$ (657,884)	$ 12,774,515	$ 700,340	$ 1,249,987	$ 279,618	$ (177,702)	$ 118,766	$ 650,059	$ 57,593
20	Rate of Return (line 19 divided by line 9)	6.42%	5.82%	10.17%	8.58%	-1.36%	12.19%	5.56%	9.16%	3.98%	-0.71%	1.58%	7.00%	15.91%
21	Index (Class ROR divided by System ROR)	100	91	158	134	(21)	190	86	143	62	(11)	25	109	248

Appendix J, Schedule C, page 1 of 2
Electric Cost of Service
Electric Department Embedded Cost of Service Study for Rate Year #1

	Levelized Electric RY #1 Revenue Requirement @	**Target ROR**	**7.43%**												
					Residential			Small General Service			Large General Service		SC5 Area	SC8 Street	SC9 Traffic
			Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
	Production:														
1	Demand - Capacity	DSUWN	$ 7,073,024	$ 3,156,986	$ 552,743	$ 49,525	$ 306,838	$ 1,643,117	$ 256,788	$ 288,930	$ 132,487	$ 653,637	$ 10,603	$ 18,594	$ 2,776
2	Demand - Generation	DAVGKW	$ 7,076,982	$ 2,348,706	$ 423,241	$ 39,036	$ 236,975	$ 2,037,610	$ 331,856	$ 376,835	$ 209,656	$ 1,020,327	$ 17,526	$ 30,731	$ 4,482
3	Commodity	COMMOD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	MFC Supply	CUNITS	$ 4,419,335	$ 3,341,165	$ 375,883	$ 22,869	$ 422,954	$ 179,738	$ 2,502	$ 469	$ 102	$ 87	$ 66,248	$ 3,006	$ 4,312
5	Total Production		$ 18,569,340	$ 8,846,856	$ 1,351,867	$ 111,430	$ 966,767	$ 3,860,465	$ 591,147	$ 666,234	$ 342,244	$ 1,674,051	$ 94,377	$ 52,331	$ 11,571
	Transmission & Subtransmission:														
6	Power Supply Trans - Subs	DSUWN	$ 18,934,463	$ 8,451,240	$ 1,479,693	$ 132,577	$ 821,405	$ 4,398,620	$ 687,422	$ 773,465	$ 354,667	$ 1,749,784	$ 28,383	$ 49,777	$ 7,431
7	Power Supply Trans - Lines	DSPK	$ 38,015,255	$ 17,848,402	$ 1,810,147	$ 239,026	$ 1,771,837	$ 9,136,228	$ 1,350,347	$ 1,570,407	$ 724,713	$ 3,550,365	$ -	$ -	$ 13,784
8	Common Trans - Subs	DNCPTS	$ 241,572	$ 58,461	$ 10,540	$ 1,113	$ 6,209	$ 29,519	$ 4,369	$ 59,200	$ -	$ 71,159	$ 353	$ 608	$ 41
9	Common Trans - Lines	DNCPTL	$ 401,633	$ 111,729	$ 20,144	$ 2,128	$ 11,866	$ 56,415	$ 8,351	$ 11,055	$ -	$ 178,032	$ 674	$ 1,161	$ 79
10	Specific - Subs	STSUB	$ 2,251,580	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,220	$ 451,358	$ 1,782,002	$ -	$ -	$ -
11	Specific - Lines	STLNS	$ 180,377	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 180,377	$ -	$ -	$ -
12	General Subtrans Lines	DNCPGT	$ 1,826,413	$ 809,354	$ 144,641	$ 13,301	$ 87,022	$ 421,503	$ 69,913	$ 72,086	$ 32,935	$ 161,784	$ 4,833	$ 8,475	$ 564
13	Total Transmission & Subtransmission		$ 61,851,294	$ 27,279,187	$ 3,465,164	$ 388,145	$ 2,698,339	$ 14,042,285	$ 2,120,401	$ 2,504,434	$ 1,563,672	$ 7,673,504	$ 34,243	$ 60,020	$ 21,899
	Bulk Distribution:														
14	Distribution Substations	DSUBS	$ 20,741,849	$ 10,084,833	$ 1,802,278	$ 165,737	$ 1,084,320	$ 5,252,078	$ 871,136	$ 898,222	$ 410,385	$ -	$ 60,225	$ 105,601	$ 7,033
15	Primary Lines - Demand	DPRIM	$ 18,192,745	$ 9,023,984	$ 1,612,692	$ 148,302	$ 970,258	$ 4,699,598	$ 779,499	$ 803,736	$ -	$ -	$ 53,889	$ 94,493	$ 6,294
16	Primary Lines - Customer	CPRIM	$ 39,785,833	$ 30,080,705	$ 3,384,093	$ 205,890	$ 3,807,879	$ 1,618,188	$ 22,528	$ 4,227	$ -	$ -	$ 596,439	$ 27,060	$ 38,825
17	Line Transformers - Demand	DTRNSF	$ 5,572,816	$ 3,385,338	$ 577,656	$ 43,808	$ 352,861	$ 1,181,805	$ -	$ -	$ -	$ -	$ 10,922	$ 19,151	$ 1,276
18	Line Transformers - Customer	CSECY	$ 6,380,113	$ 4,827,031	$ 543,043	$ 33,039	$ 611,048	$ 259,670	$ -	$ -	$ -	$ -	$ 95,710	$ 4,342	$ 6,230
19	Secondary Lines - Demand	DSECY	$ 6,111,515	$ 3,882,292	$ 650,848	$ 45,218	$ 399,935	$ 1,108,594	$ -	$ -	$ -	$ -	$ 8,580	$ 15,045	$ 1,002
20	Secondary Lines - Customer	CSECY	$ 20,201,643	$ 15,284,048	$ 1,719,463	$ 104,613	$ 1,934,788	$ 822,203	$ -	$ -	$ -	$ -	$ 303,051	$ 13,749	$ 19,727
21	Services - Demand	DSVCES	$ 2,830,922	$ 2,207,677	$ 370,107	$ 25,714	$ 227,424	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Services - Customer	CSVCES	$ 1,973,853	$ 1,611,994	$ 106,475	$ 9,370	$ 246,013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Total Bulk Distribution		$ 121,791,289	$ 80,387,902	$ 10,766,656	$ 781,691	$ 9,634,526	$ 14,942,135	$ 1,673,164	$ 1,706,184	$ 410,385	$ -	$ 1,128,817	$ 279,442	$ 80,387
24	Meter Installations, CTs & PTs	CMTRS2	$ 6,466,019	$ -	$ -	$ -	$ -	$ 5,711,076	$ 431,497	$ 207,553	$ 53,801	$ 62,092	$ -	$ -	$ -
25	Installations on Customer Premises - Plant	CINSTP	$ 636,464	$ 114,222	$ 31,460	$ 1,195	$ -	$ -	$ -	$ -	$ -	$ -	$ 489,587	$ -	$ -
26	Installations on Customer Premises - Exp	CINSTX	$ 6,756,868	$ 4,309,760	$ 624,870	$ 46,849	$ 414,206	$ 1,233,121	$ 106,454	$ -	$ -	$ -	$ 21,609	$ -	$ -
27	Street Lighting	CLGTNG	$ 3,658,136	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,658,136	$ -
28	Meter Ownership (re: line 24)	CMTRS	$ 2,932,628	$ 1,939,897	$ 225,429	$ 48,803	$ 399,128	$ 301,964	$ 9,658	$ 4,081	$ 1,207	$ 2,461	$ -	$ -	$ -
29	Meter Services / Maintenance (re: line 24)	CMTRS3	$ 4,220,083	$ 2,552,237	$ 299,823	$ 85,011	$ 570,450	$ 673,726	$ 21,548	$ 9,105	$ 2,692	$ 5,490	$ -	$ -	$ -
30	Meter Reading (902)	CMTRS4	$ 10,474,655	$ 7,013,821	$ 789,058	$ 48,007	$ 1,775,742	$ 754,615	$ 10,506	$ 59,132	$ 12,802	$ 10,973	$ -	$ -	$ -
31	DS Uncollectibles, Credit & Collections (903, 904, 905)	CODBT	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ -	$ -	$ -
32	Bill Printing, Mailing & Receipt Services (903, 905)	CNBLS	$ 2,905,885	$ 1,904,199	$ 214,223	$ 13,033	$ 482,100	$ 204,872	$ 2,852	$ 535	$ 116	$ 99	$ 75,513	$ 3,426	$ 4,915
33	Customer Account Services (901-905)	CUSTAC	$ 20,789,323	$ 12,990,636	$ 1,794,207	$ 130,149	$ 1,412,146	$ 3,112,283	$ 257,486	$ 306,648	$ 104,493	$ 245,833	$ 188,298	$ 228,854	$ 18,290
34	MFC Admin	CUNITS	$ 4,346,995	$ 3,286,474	$ 369,730	$ 22,495	$ 416,031	$ 176,795	$ 2,461	$ 462	$ 100	$ 86	$ 65,164	$ 2,956	$ 4,242
35	Sales & Customer Services (907-916)	CUSVCS3	$ 9,563,513	$ 7,230,336	$ 813,416	$ 49,489	$ 915,279	$ 388,955	$ 5,415	$ 1,016	$ 220	$ 189	$ 143,363	$ 6,504	$ 9,332
36	OTHER Revenues	OSALES	$ (8,369,485)	$ (4,138,911)	$ (844,471)	$ (54,161)	$ (353,077)	$ (875,215)	$ (59,276)	$ (72,034)	$ (118,447)	$ (1,645,395)	$ (205,274)	$ (1,210)	$ (2,012)
37	Sales Revenues	RSALES													
38	Total Levelized Electric RY #1 Revenue Requirement @		$ 266,593,008	$ 153,716,614	$ 19,901,434	$ 1,672,136	$ 19,331,638	$ 44,527,078	$ 5,173,313	$ 5,393,349	$ 2,373,285	$ 8,029,382	$ 2,035,696	$ 4,290,459	$ 148,624
39	Demand-related		$ 122,374,164	$ 59,020,296	$ 9,031,490	$ 866,449	$ 6,039,976	$ 27,927,476	$ 4,027,826	$ 4,495,322	$ 2,106,544	$ 8,327,141	$ 178,462	$ 312,905	$ 40,279
40	Energy-related		$ 11,496,316	$ 5,689,871	$ 799,123	$ 61,905	$ 659,929	$ 2,217,347	$ 334,358	$ 377,304	$ 209,758	$ 1,020,414	$ 83,774	$ 33,737	$ 8,795
41	Commodity-related		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	Customer-related		$ 141,092,012	$ 93,145,359	$ 10,915,292	$ 797,944	$ 12,984,811	$ 15,257,469	$ 870,405	$ 592,757	$ 175,430	$ 327,222	$ 1,978,734	$ 3,945,027	$ 101,562
43	Revenue		$ (8,369,485)	$ (4,138,911)	$ (844,471)	$ (54,161)	$ (353,077)	$ (875,215)	$ (59,276)	$ (72,034)	$ (118,447)	$ (1,645,395)	$ (205,274)	$ (1,210)	$ (2,012)
	Check		-	-	-	-	-	-	-	-	-	-	-	-	-

Appendix J, Schedule C, page 2 of 2
Electric Cost of Service
Electric Department Embedded Cost of Service Study for Rate Year #1

				Residential			Small General Service			Large General Service			SC5 Area	SC8 Street	SC9 Traffic
			Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
	Revenue Requirements for bundled functions @ ROR on RB =	**7.43%**													
44	Demand-related functions	L 39-f43	$ 120,031,879	$ 58,805,407	$ 8,775,878	$ 863,931	$ 6,021,312	$ 27,825,862	$ 4,008,562	$ 4,472,060	$ 1,992,211	$ 6,735,157	$ 178,462	$ 312,905	$ 40,134
45	Energy-related functions	L40 - L48	$ 7,076,982	$ 2,348,706	$ 423,241	$ 39,036	$ 236,975	$ 2,037,610	$ 331,856	$ 376,835	$ 209,656	$ 1,020,327	$ 17,526	$ 30,731	$ 4,482
46	Customer-related functions	L42-f43-49:54	$ 110,187,585	$ 72,526,203	$ 8,428,473	$ 528,970	$ 9,007,073	$ 12,372,210	$ 783,389	$ 470,697	$ 154,443	$ 255,296	$ 1,632,857	$ 3,937,435	$ 90,538
47	sub-total		$ 237,296,446	$ 133,680,315	$ 17,627,592	$ 1,431,938	$ 15,265,360	$ 42,235,682	$ 5,123,807	$ 5,319,591	$ 2,356,310	$ 8,010,780	$ 1,828,845	$ 4,281,072	$ 135,155
	Revenue Requirements for Unbundled Functions														
48	MFC Supply	L 4	$ 4,419,335	$ 3,341,165	$ 375,883	$ 22,869	$ 422,954	$ 179,738	$ 2,502	$ 469	$ 102	$ 87	$ 66,248	$ 3,006	$ 4,312
49	Meter Ownership function	L 28	$ 2,932,628	$ 1,939,897	$ 225,429	$ 48,803	$ 399,128	$ 301,964	$ 9,658	$ 4,081	$ 1,207	$ 2,461	$ -	$ -	$ -
50	Meter Services function	L 29	$ 4,220,083	$ 2,552,237	$ 299,823	$ 85,011	$ 570,450	$ 673,726	$ 21,548	$ 9,105	$ 2,692	$ 5,490	$ -	$ -	$ -
51	Meter Reading function	L 30	$ 10,474,655	$ 7,013,821	$ 789,058	$ 48,007	$ 1,775,742	$ 754,615	$ 10,506	$ 59,132	$ 12,802	$ 10,973	$ -	$ -	$ -
52	DS Uncollectibles, Credit & Collections function	L 31	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ -	$ -	$ -
53	Bill Printing, Mailing & Receipt function	L 32	$ 2,905,885	$ 1,904,199	$ 214,223	$ 13,033	$ 482,100	$ 204,872	$ 2,852	$ 535	$ 116	$ 99	$ 75,513	$ 3,426	$ 4,915
54	MFC Admin	L 34	$ 4,346,995	$ 3,286,474	$ 369,730	$ 22,495	$ 416,031	$ 176,795	$ 2,461	$ 462	$ 100	$ 86	$ 65,164	$ 2,956	$ 4,242
55	sub-total		$ 29,299,582	$ 20,037,793	$ 2,274,147	$ 240,218	$ 4,066,405	$ 2,291,711	$ 49,528	$ 73,784	$ 17,018	$ 19,196	$ 206,925	$ 9,388	$ 13,470
56	Total Delivery Service Revenue Requirement	L47 + L55	$ 266,596,028	$ 153,718,108	$ 19,901,738	$ 1,672,156	$ 19,331,765	$ 44,527,393	$ 5,173,335	$ 5,393,375	$ 2,373,328	$ 8,029,976	$ 2,035,770	$ 4,290,460	$ 148,624
	Billing Units														
57	Average Monthly Sigma NCPi @ meter, kW		2,013,583	1,094,221	168,404	12,630	96,864	390,985	55,116	55,017	25,392	114,953	0	0	0
58	Deliveries as measured @ meter, MWh		5,342,342	1,744,845	314,424	29,000	176,048	1,513,733	253,806	288,206	165,640	817,460	13,020	22,830	3,330
59	Number of Customers		304,363	230,109	25,887	1,575	29,129	12,379	172	32	7	6	4,563	207	297
	Levelized Full Service DS Rates based on ROR =	**7.43%**													
60	Demand Rate, $ / kW / month	L44 / L57 / 12	$4.97	$0.00	$0.00	$0.00	$0.00	$5.93	$6.06	$6.77	$6.54	$4.88	$0.00	$0.00	$0.00
61	Energy Rate $ / kWh @ mtr (excluding commodity chgs)	L40 / L58	$ 0.00215	$ 0.03696	$ 0.03045	$ 0.03193	$ 0.03795	$ 0.00146	$ 0.00132	$ 0.00131	$ 0.00127	$ 0.00125	$ 0.02014	$ 0.01518	$ 0.01469
62	Customer Rate, $ / mo	L42-f43/L59/12	$36.98	$32.31	$33.24	$39.49	$36.19	$97.51	$401.55	$1,402.09	$2,040.00	$3,811.17	$32.39	$1,587.69	$27.97
	Potential Backout Credits available to Customers														
63	MFC Supply $ / kWh delivered @ Meter level	L48 / L58	$ 0.00083	$ 0.00191	$ 0.00120	$ 0.00079	$ 0.00240	$ 0.00012	$ 0.00001	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.00509	$ 0.00013	$ 0.00130
64	Meter Ownership Rate $ / month	L49 / L59 / 12	$0.80	$0.70	$0.73	$2.58	$1.14	$2.03	$4.67	$10.52	$14.36	$34.18	$0.00	$0.00	$0.00
65	Meter Services Rate $ / month	L50 / L59 / 12	$1.16	$0.92	$0.97	$4.50	$1.63	$4.54	$10.42	$23.47	$32.05	$76.25	$0.00	$0.00	$0.00
66	Meter Reading Rate $ / month	L51 / L59 / 12	$2.87	$2.54	$2.54	$2.54	$5.08	$5.08	$5.08	$152.40	$152.40	$152.40	$0.00	$0.00	$0.00
67	Dlvry Srvc Uncollectibles, Credit & Collections Rate $ / month	L52 / L59 / 12	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	$0.00	$0.00	$0.00
68	Bill Printing & Receipt Services Rate $ / month	L53 / L59 / 12	$0.80	$0.69	$0.69	$0.69	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38
69	MFC Admin Rate $ / month	L54 / L59 / 12	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19	$1.19
	Delivery Service Rates and MFCs @ ROR =	**7.43%**													
70	Demand Rate, $ / kW / month	L 60	$4.97	$0.00	$0.00	$0.00	$0.00	$5.93	$6.06	$6.77	$6.54	$4.88	$0.00	$0.00	$0.00
71	Energy Rate (Net of MFC Supply) in $ / kWh	L61 - L63	$ 0.00132	$ 0.00135	$ 0.00135	$ 0.00135	$ 0.00135	$ 0.00135	$ 0.00131	$ 0.00131	$ 0.00127	$ 0.00125	$ 0.00135	$ 0.00135	$ 0.00135
72	Customer Rate (Net of MFC Admin) in $ / month	L62- L67- L69	$35.79	$31.12	$32.05	$38.30	$35.00	$96.32	$400.36	$1,400.90	$2,038.81	$3,809.98	$31.20	$1,586.50	$26.78
73	Supply Charge $ / kWh	L48/L58	$ 0.00083	$ 0.00191	$ 0.00120	$ 0.00079	$ 0.00240	$ 0.00012	$ 0.00001	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.00509	$ 0.00013	$ 0.00130
74	Admin. Charge: $ / kWh	L54/L58	$ 0.00081	$ 0.00188	$ 0.00118	$ 0.00078	$ 0.00236	$ 0.00012	$ 0.00001	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.00500	$ 0.00013	$ 0.00127
	Current (Jul '09) Delivery Service Rates														
75	Demand Rate, $ / kW / month			$0.00	$0.00	$0.00	$0.00	$8.00	$6.30	$8.42	$6.21	$3.34	$0.00	$0.00	$0.00
76	Energy Rate $ / kWh (excluding commodity chgs)			$ 0.04691	$ 0.04691	07892/.02630	$ 0.00340	$ 0.00522	$ 0.00135	$ -	$ -	$ -	rates based on lamp type		
77	Customer Rate, $ / mo			$18.00	$18.00	$21.00	$30.00	$50.00	$160.00	$620.00	$800.00	$800.00	$0.00	$0.00	$0.00

Appendix J, Schedule D
Electric Cost of Service
Electric Department Delivery-Only HYPOTHETICAL Rate of Return Statement

			Residential			Small General Service			Large General Service			SC5 Area	SC8 Street	SC9 Traffic
	Rate Base:	Total System	SC1 Non-heat	SC1 Heat	SC6 TOU	SC2 non-dmnd	SC2 sec-dmnd	SC2 pri-dmnd	SC3 Primary	SC13 Subs	SC13 Trans	Lighting	Lighting	Lighting
1	Gross Plant in Service	$ 841,316,671	$ 489,299,794	$ 67,516,914	$ 6,442,141	$ 59,079,985	$ 122,775,599	$ 13,229,896	$ 18,153,717	$ 8,604,783	$ 34,783,745	$ 9,451,981	$ 11,516,713	$ 461,404
2	less: Accum. Provisions for Depr. & Amort.	$ 259,703,270	$ 148,086,769	$ 20,545,534	$ 1,981,073	$ 17,791,314	$ 39,612,927	$ 4,372,811	$ 6,025,007	$ 2,845,644	$ 12,084,618	$ 2,746,088	$ 3,471,071	$ 140,414
3	Net Plant in Service	$ 581,613,401	$ 341,213,024	$ 46,971,380	$ 4,461,068	$ 41,288,671	$ 83,162,671	$ 8,857,085	$ 12,128,710	$ 5,759,140	$ 22,699,127	$ 6,705,893	$ 8,045,642	$ 320,990
4	plus: Construction Work in Progress	$ 32,990,000	$ 19,224,127	$ 2,661,621	$ 254,315	$ 2,294,942	$ 4,738,772	$ 519,969	$ 721,777	$ 347,067	$ 1,401,195	$ 382,015	$ 426,233	$ 17,967
5	plus: Working Capital	$ 32,126,856	$ 18,744,687	$ 2,523,846	$ 237,246	$ 2,364,400	$ 4,954,467	$ 482,212	$ 625,670	$ 258,506	$ 1,065,118	$ 306,531	$ 544,140	$ 20,033
6	less: Accumulated Deferred Income Taxes	$ 75,995,000	$ 42,621,022	$ 5,914,204	$ 580,291	$ 5,126,128	$ 11,772,966	$ 1,386,213	$ 1,911,664	$ 904,739	$ 3,831,431	$ 819,150	$ 1,086,912	$ 40,281
7	plus: Deferred Charges	$ (40,844,000)	$ (23,909,916)	$ (3,304,963)	$ (315,380)	$ (2,857,829)	$ (5,811,328)	$ (633,430)	$ (878,071)	$ (421,682)	$ (1,679,320)	$ (477,581)	$ (532,257)	$ (22,241)
8	less: Other Rate Base Deductions	$ (7,380,000)	$ (4,235,109)	$ (589,508)	$ (57,228)	$ (512,475)	$ (1,108,858)	$ (118,615)	$ (162,233)	$ (80,023)	$ (312,173)	$ (84,042)	$ (115,918)	$ (3,818)
9	Total Rate Base	$ 537,271,257	$ 316,886,010	$ 43,527,187	$ 4,114,184	$ 38,476,532	$ 76,380,475	$ 7,958,237	$ 10,848,654	$ 5,118,315	$ 19,966,862	$ 6,181,750	$ 7,512,764	$ 300,286
	Revenues:													
10	Electric Delivery Revenues	$ 194,379,244	$ 105,038,768	$ 16,356,535	$ 1,680,849	$ 8,781,290	$ 43,167,590	$ 3,372,014	$ 5,309,453	$ 1,430,059	$ 4,788,739	$ 1,000,995	$ 3,272,051	$ 180,901
11	Other Revenues	$ 41,623,263	$ 17,614,425	$ 2,881,257	$ 292,281	$ 1,644,335	$ 9,532,308	$ 1,104,058	$ 1,634,352	$ 731,802	$ 5,496,048	$ 325,323	$ 340,259	$ 26,816
12	Total Operating Revenues	$ 236,002,507	$ 122,653,192	$ 19,237,792	$ 1,973,129	$ 10,425,625	$ 52,699,898	$ 4,476,072	$ 6,943,805	$ 2,161,860	$ 10,284,787	$ 1,326,319	$ 3,612,310	$ 207,716
	Expenses:													
13	Operation and Maintenance	$ 129,216,049	$ 75,210,337	$ 9,938,632	$ 924,197	$ 9,816,498	$ 21,004,561	$ 1,898,618	$ 2,343,871	$ 835,841	$ 3,591,529	$ 1,037,232	$ 2,526,654	$ 88,079
14	Depreciation and Amortization	$ 22,251,467	$ 13,003,591	$ 1,790,157	$ 170,089	$ 1,579,897	$ 3,220,683	$ 341,819	$ 466,289	$ 220,714	$ 878,254	$ 252,627	$ 315,045	$ 12,301
15	Taxes Other than Income	$ 27,063,824	$ 13,084,614	$ 1,734,587	$ 203,582	$ 1,356,811	$ 5,797,221	$ 714,411	$ 1,048,586	$ 438,453	$ 2,430,258	$ 66,923	$ 175,422	$ 12,956
16	Federal Income Tax	$ 13,999,942	$ 4,300,274	$ 1,496,072	$ 182,292	$ (1,045,317)	$ 6,538,288	$ 419,677	$ 898,717	$ 177,231	$ 947,456	$ (52,072)	$ 109,789	$ 27,535
17	NYS Income Tax	$ 3,460,228	$ 1,114,208	$ 356,605	$ 42,959	$ (215,514)	$ 1,555,974	$ 101,365	$ 210,273	$ 41,641	$ 224,264	$ (12,875)	$ 34,853	$ 6,475
18	Total Operating Expenses	$ 195,991,510	$ 106,713,024	$ 15,316,053	$ 1,523,120	$ 11,492,375	$ 38,116,727	$ 3,475,890	$ 4,967,735	$ 1,713,880	$ 8,071,761	$ 1,291,834	$ 3,161,763	$ 147,346
19	Net Operating Income (line12 less line 18)	$ 40,010,997	$ 15,940,168	$ 3,921,739	$ 450,009	$ (1,066,750)	$ 14,583,171	$ 1,000,183	$ 1,976,070	$ 447,981	$ 2,213,026	$ 34,485	$ 450,547	$ 60,370
20	Rate of Return (line 19 divided by line 9)	7.45%	5.03%	9.01%	10.94%	-2.77%	19.09%	12.57%	18.21%	8.75%	11.08%	0.56%	6.00%	20.10%
21	Index (Class ROR divided by System ROR)	100	68	121	147	(37)	256	169	245	118	149	7	81	270

These results are hypothetical only and do not necessarily depict the results that may have been achieved if Central Hudson operated as a delivery-only company.

Appendix K, Schedule A
Gas Cost of Service
Gas Department 2007 Rate of Return Statement

			Residential		Commercial / Industrial		SC8/9	Firm		Firm	Firm
	Rate Base:	Total System	Heating	Non-heat	Heating	Non-heat	Interruptible	SC11 dlm	Intrdprtmntl	SC11 t	SC11 d
1	Gross Plant in Service	$ 259,679,369	$ 140,285,239	$ 17,895,714	$ 71,581,687	$ 7,440,615	$ 1,751,852	$ 2,898,136	$ 13,069,383	$ 4,017,145	$ 739,597
2	less: Accum. Provisions for Depr. & Amort.	$ 95,813,000	$ 45,700,608	$ 5,510,926	$ 24,938,216	$ 2,559,908	$ 531,609	$ 1,146,101	$ 13,302,741	$ 1,868,659	$ 254,232
3	Net Plant in Service	$ 163,866,369	$ 94,584,631	$ 12,384,788	$ 46,643,472	$ 4,880,707	$ 1,220,243	$ 1,752,035	$ (233,358)	$ 2,148,487	$ 485,365
4	plus: Construction Work in Progress	$ 7,353,000	$ 4,244,195	$ 555,729	$ 2,092,983	$ 219,007	$ 54,755	$ 78,617	$ (10,471)	$ 96,407	$ 21,779
5	plus: Working Capital	$ 23,730,249	$ 11,909,180	$ 822,961	$ 8,872,112	$ 823,070	$ 941,594	$ 74,755	$ 169,637	$ 97,623	$ 19,316
6	less: Accumulated Deferred Income Taxes	$ 27,270,000	$ 14,994,249	$ 1,813,965	$ 8,175,477	$ 840,017	$ 176,577	$ 400,281	$ 113,893	$ 669,030	$ 86,512
7	plus: Deferred Charges	$ 4,267,000	$ 2,430,156	$ 310,983	$ 1,234,039	$ 128,363	$ 30,412	$ 51,980	$ (5,354)	$ 73,343	$ 13,078
8	less: Other Rate Base Deductions	$ 13,907,249	$ 7,935,306	$ 989,571	$ 4,103,649	$ 421,920	$ 167,808	$ 126,290	$ (15,697)	$ 141,678	$ 36,724
9	Total Rate Base	$ 158,039,369	$ 90,238,607	$ 11,270,926	$ 46,563,479	$ 4,789,209	$ 1,902,619	$ 1,430,817	$ (177,743)	$ 1,605,151	$ 416,303
	Revenues:										
10	Sales, Transport & Dlvry Srvc Revenues	$ 145,945,217	$ 74,330,740	$ 4,397,589	$ 52,925,779	$ 5,412,902	$ 6,655,279	$ 516,810	$ 301,390	$ 1,258,150	$ 146,578
11	Miscellaneous Revenues	$ 19,804,484	$ 9,005,651	$ 376,102	$ 8,664,903	$ 1,280,324	$ -	$ -	$ 477,504	$ -	$ -
12	Total Operating Revenues	$ 165,749,701	$ 83,336,391	$ 4,773,691	$ 61,590,682	$ 6,693,226	$ 6,655,279	$ 516,810	$ 778,894	$ 1,258,150	$ 146,578
	Expenses:										
13	Operation and Maintenance	$ 137,892,300	$ 67,788,892	$ 3,982,808	$ 53,465,142	$ 4,908,209	$ 6,171,031	$ 310,532	$ 746,583	$ 444,041	$ 75,062
14	Depreciation and Amortization	$ 6,147,731	$ 3,422,887	$ 423,864	$ 1,814,874	$ 187,387	$ 41,391	$ 83,315	$ 23,726	$ 131,175	$ 19,113
15	Taxes Other than Income	$ 7,512,657	$ 4,147,840	$ 486,581	$ 2,370,967	$ 272,791	$ 48,970	$ 67,877	$ 13,555	$ 85,531	$ 18,546
16	Federal Income Tax	$ 3,653,670	$ 2,058,978	$ (102,186)	$ 980,604	$ 401,070	$ 108,941	$ 12,103	$ (6,221)	$ 191,537	$ 8,843
17	NYS Income Tax	$ 511,831	$ 290,976	$ (41,613)	$ 129,713	$ 79,265	$ 22,347	$ (926)	$ (5,758)	$ 36,703	$ 1,124
18	Total Operating Expenses	$ 155,718,188	$ 77,709,572	$ 4,749,453	$ 58,761,300	$ 5,848,722	$ 6,392,681	$ 472,900	$ 771,884	$ 888,987	$ 122,688
19	Net Operating Income (line12 less line 18)	$ 10,031,513	$ 5,626,819	$ 24,238	$ 2,829,382	$ 844,504	$ 262,598	$ 43,910	$ 7,010	$ 369,163	$ 23,890
20	Rate of Return (line 19 divided by line 9)	6.35%	6.24%	0.22%	6.08%	17.63%	13.80%	3.07%	-3.94%	23.00%	5.74%
21	Index (Class ROR divided by System ROR)	100	98	3	96	278	217	48	(62)	362	90

Appendix K, Schedule B
Gas Cost of Service
Gas Department RY #1 Rate of Return Statement

			Residential		Commercial / Industrial		SC8/9	Firm		Firm	Firm
	Rate Base:	Total System	Heating	Non-heat	Heating	Non-heat	Interruptible	SC11 dlm	Intrdprtmntl	SC11 t	SC11 d
1	Gross Plant in Service	$ 311,390,000	$ 174,380,004	$ 19,469,246	$ 84,838,540	$ 9,795,057	$ -	$ 3,693,367	$ 13,991,819	$ 4,761,685	$ 460,281
2	less: Accum. Provisions for Depr. & Amort.	$ 105,053,822	$ 52,879,547	$ 5,686,517	$ 27,006,709	$ 3,102,279	$ -	$ 1,356,281	$ 12,794,757	$ 2,080,654	$ 147,078
3	Net Plant in Service	$ 206,336,178	$ 121,500,457	$ 13,782,730	$ 57,831,831	$ 6,692,777	$ -	$ 2,337,086	$ 1,197,062	$ 2,681,032	$ 313,203
4	plus: Construction Work in Progress	$ 8,581,000	$ 5,052,897	$ 573,189	$ 2,405,080	$ 278,336	$ -	$ 97,193	$ 49,783	$ 111,497	$ 13,025
5	plus: Working Capital	$ 8,894,000	$ 5,040,018	$ 577,685	$ 2,585,976	$ 304,404	$ -	$ 98,481	$ 148,240	$ 126,653	$ 12,543
6	less: Accumulated Deferred Income Taxes	$ 37,035,000	$ 20,793,339	$ 2,182,328	$ 10,986,232	$ 1,259,731	$ -	$ 601,991	$ 153,679	$ 997,379	$ 60,321
7	plus: Deferred Charges	$ 3,473,000	$ 1,943,288	$ 202,552	$ 1,025,864	$ 117,263	$ -	$ 59,482	$ 18,397	$ 100,331	$ 5,823
8	less: Other Rate Base Deductions	$ 127,000	$ 75,392	$ 8,690	$ 35,157	$ 4,081	$ -	$ 1,318	$ 835	$ 1,339	$ 189
9	Total Rate Base	$ 190,122,178	$ 112,667,930	$ 12,945,137	$ 52,827,361	$ 6,128,967	$ -	$ 1,988,933	$ 1,258,969	$ 2,020,796	$ 284,085
	Revenues:										
10	Sales, Transport & Dlvry Srvc Revenues	$ 66,664,700	$ 39,809,214	$ 2,925,487	$ 19,107,533	$ 2,755,859	$ -	$ 655,082	$ 56,130	$ 1,282,089	$ 73,307
11	Miscellaneous Revenues	$ 1,596,760	$ 1,144,833	$ 64,190	$ 345,474	$ 42,263	$ -	$ -	$ -	$ -	$ -
12	Total Operating Revenues	$ 68,261,460	$ 40,954,047	$ 2,989,677	$ 19,453,007	$ 2,798,121	$ -	$ 655,082	$ 56,130	$ 1,282,089	$ 73,307
	Expenses:										
13	Operation and Maintenance	$ 35,419,000	$ 19,651,306	$ 2,264,383	$ 10,774,615	$ 1,287,848	$ -	$ 373,942	$ 507,918	$ 512,570	$ 46,419
14	Depreciation and Amortization	$ 7,571,000	$ 4,316,394	$ 464,810	$ 2,208,295	$ 253,932	$ -	$ 112,291	$ 29,991	$ 173,179	$ 12,108
15	Taxes Other than Income	$ 9,377,000	$ 5,634,811	$ 590,465	$ 2,581,793	$ 301,616	$ -	$ 92,388	$ 54,577	$ 109,103	$ 12,247
16	Federal Income Tax	$ 4,304,564	$ 3,180,452	$ (171,752)	$ 1,029,197	$ 284,071	$ -	$ 20,244	$ (199,049)	$ 161,804	$ (404)
17	NYS Income Tax	$ 806,421	$ 613,730	$ (34,463)	$ 185,749	$ 53,957	$ -	$ (367)	$ (37,348)	$ 25,473	$ (311)
18	Total Operating Expenses	$ 57,477,985	$ 33,396,693	$ 3,113,444	$ 16,779,649	$ 2,181,423	$ -	$ 598,498	$ 356,088	$ 982,130	$ 70,059
19	Net Operating Income (line12 less line 18)	$ 10,783,475	$ 7,557,354	$ (123,767)	$ 2,673,358	$ 616,698	$ -	$ 56,584	$ (299,958)	$ 299,959	$ 3,247
20	Rate of Return (line 19 divided by line 9)	5.67%	6.71%	-0.96%	5.06%	10.06%	0.00%	2.84%		14.84%	1.14%
21	Index (Class ROR divided by System ROR)	100	118	(17)	89	177	-	50		262	20

Appendix K, Schedule C, Page 1 of 2
Gas Cost of Service
Gas Department Embedded Cost of Service Study for Rate Year #1

				Residential		Commercial / Industrial		SC8/9	Firm		Firm	Firm
			Total System	Heating	Non-heat	Heating	Non-heat	Interruptible	SC11 dlm	Intrdprtmntl	SC11 t	SC11 d
	Levelized RY Gas Revenue Requirement @ Target ROR =	**7.43%**										
	Production:											
1	Demand - Capacity	DFWPK	$ 1,024,613	$ 488,826	$ 13,624	$ 468,432	$ 50,813	$ -	$ -	$ 2,918	$ -	$ -
2	Demand - Generation	DAVGMCF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Commodity	COMMOD	$ (68,149)	$ (26,296)	$ (997)	$ (26,661)	$ (4,147)	$ -	$ (3,872)	$ (112)	$ (5,861)	$ (204)
4	MFC Supply	DAVGMCF	$ 1,216,852	$ 550,742	$ 20,873	$ 558,381	$ 86,857	$ -	$ -	$ -	$ -	$ -
5	Total Production		$ 2,173,316	$ 1,013,272	$ 33,500	$ 1,000,152	$ 133,523	$ -	$ (3,872)	$ 2,806	$ (5,861)	$ (204)
	Transmission & Subtransmission:											
6	Supply Trans - Reg Stations	DWPK	$ 4,065,147	$ 1,653,276	$ 46,077	$ 1,584,299	$ 171,858	$ -	$ 177,532	$ 9,869	$ 411,493	$ 10,744
7	Supply Trans - Lines	DWPK	$ 12,954	$ 5,268	$ 147	$ 5,048	$ 548	$ -	$ 566	$ 31	$ 1,311	$ 34
8	Common Trans - Reg Stations	DWPK	$ 1,482,945	$ 603,107	$ 16,808	$ 577,944	$ 62,693	$ -	$ 64,763	$ 3,600	$ 150,110	$ 3,919
9	Common Trans - Lines	DWPK	$ 249	$ 101	$ 3	$ 97	$ 11	$ -	$ 11	$ 1	$ 25	$ 1
10	T&D Equip for Spfc Cstmrs @ Trans PSI	STSUB	$ 218,848	$ 12,823	$ 425	$ 12,724	$ 1,311	$ -	$ 51,254	$ 928	$ 139,384	$ -
11	Specific Iroquois Lines	STLNS	$ 420,890	$ -	$ -	$ -	$ -	$ -	$ -	$ 420,890	$ -	$ -
12	General Reg Stations / Lines	DWPK	$ 3,200,573	$ 1,301,658	$ 36,277	$ 1,247,351	$ 135,307	$ -	$ 139,775	$ 7,770	$ 323,977	$ 8,459
13	Total Transmission & Subtransmission		$ 9,401,606	$ 3,576,234	$ 99,736	$ 3,427,464	$ 371,727	$ -	$ 433,900	$ 443,089	$ 1,026,300	$ 23,157
	Bulk Distribution:											
14	Distribution Reg Stations	DMAINS	$ 2,224,593	$ 1,038,057	$ 28,930	$ 994,748	$ 107,906	$ -	$ 42,009	$ 6,196	$ -	$ 6,746
15	Bulk Mains & Mtr Stations - Demand	DMAINS	$ 17,185,703	$ 8,019,330	$ 223,497	$ 7,684,752	$ 833,608	$ -	$ 324,532	$ 47,870	$ -	$ 52,114
16	Bulk Mains & Mtr Stations - Customer	CMAINS	$ 9,253,840	$ 6,862,906	$ 1,095,436	$ 1,138,567	$ 156,636	$ -	$ 47	$ 124	$ -	$ 124
17	(reserved for future use) - Demand	DSPFC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Dist Equip of Spfc Customers (SC8 & SC11)	CORUPT	$ 409,149	$ 176,849	$ 7,065	$ 184,977	$ 27,504	$ -	$ -	$ -	$ -	$ 12,754
19	Bulk Services Demand	DSRVCS	$ 823,087	$ 391,468	$ 10,910	$ 375,135	$ 40,693	$ -	$ -	$ 2,337	$ -	$ 2,544
20	Bulk Services Customer	CSECY	$ 11,311,357	$ 8,388,973	$ 1,339,022	$ 1,391,744	$ 191,466	$ -	$ -	$ 152	$ -	$ -
21	(reserved for future use) - Demand	DSVCES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Specific Services - Customer (SC8 & SC11)	CORUPT	$ 29,045	$ 12,554	$ 502	$ 13,131	$ 1,953	$ -	$ -	$ -	$ -	$ 905
23	Total Bulk Distribution		$ 41,236,775	$ 24,890,138	$ 2,705,362	$ 11,783,055	$ 1,359,766	$ -	$ 366,588	$ 56,680	$ -	$ 75,187
24	Meters & Regulators	CMTRS	$ 7,119,589	$ 3,542,240	$ 605,175	$ 2,474,427	$ 275,518	$ -	$ 5,832	$ 200,127	$ 12,203	$ 4,068
25	Industrial Reg Stations	CINSTP	$ 114,136	$ -	$ -	$ 100,439	$ 13,698	$ -	$ -	$ -	$ -	$ -
26	Firm Customers Mtr / Reg Installations	CINSTX	$ 2,920,937	$ 2,166,026	$ 345,734	$ 359,347	$ 49,436	$ -	$ 196	$ 39	$ 118	$ 39
27	Miscellaneous Revenues	DRMISC	$ (1,596,760)	$ (1,144,833)	$ (64,190)	$ (345,474)	$ (42,263)	$ -	$ -	$ -	$ -	$ -
28	Uncollectibles, Credit & Collections on Delivery	CODBT	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)	$ (0)
29	Bill Printing, Mailing & Receipt Services	CNBLS	$ 516,651	$ 336,080	$ 53,644	$ 111,512	$ 15,341	$ -	$ 12	$ 12	$ 37	$ 12
30	Customer Account Services (901-905)	CUSTAC	$ 6,349,429	$ 4,334,461	$ 691,853	$ 1,162,186	$ 159,885	$ -	$ 502	$ 33	$ 381	$ 127
31	MFC Admin	DAVGMCF	$ 962,311	$ 435,537	$ 16,507	$ 441,579	$ 68,688	$ -	$ -	$ -	$ -	$ -
32	Sales & Customer Service (907-916)	CUSVCS3	$ 1,586,319	$ 1,031,896	$ 164,708	$ 342,386	$ 47,103	$ -	$ 37	$ 37	$ 112	$ 37
33	Sales, Transport & Dlvry Srvc Revenues	RSALES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Total Levelized Revenue Requirement from Rates		$ 70,784,309	$ 40,181,051	$ 4,652,029	$ 20,857,073	$ 2,452,422	$ -	$ 803,197	$ 702,823	$ 1,033,289	$ 102,424
35	Demand		$ 30,659,603	$ 13,513,915	$ 376,698	$ 12,950,532	$ 1,404,746	$ -	$ 800,441	$ 502,410	$ 1,026,300	$ 84,561
36	Commodity		$ 1,148,704	$ 524,446	$ 19,876	$ 531,720	$ 82,710	$ -	$ (3,872)	$ (112)	$ (5,861)	$ (204)
37	Customer		$ 40,572,763	$ 27,287,523	$ 4,319,645	$ 7,720,295	$ 1,007,229	$ -	$ 6,627	$ 200,525	$ 12,851	$ 18,067
38	Revenue		$ (1,596,760)	$ (1,144,833)	$ (64,190)	$ (345,474)	$ (42,263)	$ -	$ -	$ -	$ -	$ -
39	Check		(0.00)	(0.00)	0.00	0.00	(0.00)	-	(0.00)	(0.00)	(0.00)	(0.00)

Appendix K, Schedule C, Page 2 of 2
Gas Cost of Service
Gas Department Embedded Cost of Service Study for Rate Year #1

				Residential		Commercial / Industrial		SC8/9	Firm		Firm	Firm
			Total System	Heating	Non-heat	Heating	Non-heat	Interruptible	SC11 dlm	Intrdprtmntl	SC11 t	SC11 d
	Revenue Requirements for bundled functions @ ROR on RB =	**7.43%**										
40	Demand-related functions	L 35	$ 30,659,603	$ 13,513,915	$ 376,698	$ 12,950,532	$ 1,404,746	$ -	$ 800,441	$ 502,410	$ 1,026,300	$ 84,561
41	Commodity-related functions	L 36-L45	$ (68,149)	$ (26,296)	$ (997)	$ (26,661)	$ (4,147)	$ -	$ (3,872)	$ (112)	$ (5,861)	$ (204)
42	Customer-related functions	L37-L38-L46:48	$ 37,497,041	$ 25,371,073	$ 4,185,304	$ 6,821,730	$ 880,937	$ -	$ 6,615	$ 200,513	$ 12,814	$ 18,055
43	sub-total		$ 68,088,495	$ 38,858,692	$ 4,561,006	$ 19,745,601	$ 2,281,536	$ -	$ 803,185	$ 702,811	$ 1,033,253	$ 102,412
44	Revenue Requirements for Unbundled Functions											
45	MFC Supply	L 4	$ 1,216,852	$ 550,742	$ 20,873	$ 558,381	$ 86,857	$ -	$ -	$ -	$ -	$ -
46	DS Uncollectibles, Credit & Collections function	L 28	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)	$ (0)
47	Bill Printing, Mailing & Receipt function	L 29	$ 516,651	$ 336,080	$ 53,644	$ 111,512	$ 15,341	$ -	$ 12	$ 12	$ 37	$ 12
48	MFC Admin	L 31	$ 962,311	$ 435,537	$ 16,507	$ 441,579	$ 68,688	$ -	$ -	$ -	$ -	$ -
49	sub-total		$ 2,695,814	$ 1,322,359	$ 91,023	$ 1,111,473	$ 170,886	$ -	$ 12	$ 12	$ 37	$ 12
50	Total Delivery Service Revenue Requirement	L43+L49	$ 70,784,309	$ 40,181,051	$ 4,652,029	$ 20,857,073	$ 2,452,422	$ -	$ 803,197	$ 702,823	$ 1,033,289	$ 102,424
	RY Billing Units											
51a	GAS Deliveries @ meter (SC8&9 sales to SC1 & 2), Mcf		14,220,532	5,487,137	207,959	5,563,251	865,371	0	807,863	23,430	1,223,020	42,500
51b	GAS Deliveries @ meter, Mcf		14,220,532	4,712,507	178,601	4,777,876	743,205	1,711,530	807,863	23,430	1,223,020	42,500
52	Number of Customers		74,364	55,148	8,803	9,149	1,259	0	1	1	3	1
	Levelized Full Service DS Rates based on RY @ ROR =	**7.43%**										
53	for Demand-related functions, Rate, $ / Mcf	L35 / L51a	$ 2.16	$ 2.46	$ 1.81	$ 2.33	$ 1.62	$ -	$ 0.99	$ -	$ 0.84	$ 1.99
54	Energy functions $ / Mcf @ mtr (excluding commodity chgs)	L36 / L51a	$ 0.0808	$ 0.0956	$ 0.0956	$ 0.0956	$ 0.0956	$ -	$ (0.0048)	$ -	$ (0.0048)	$ (0.0048)
55	Customer Rate, $ / mo	L37+ L38/L52/12	$43.68	$39.50	$40.29	$67.17	$63.89	$0.00	$552.27	$0.00	$356.97	$1,505.59
	Potential MFC Rates /Billing Credit											
56	Supply $ / Mcf at meter	L45 / L51b	$ 0.0856	$ 0.1169	$ 0.1169	$ 0.1169	$ 0.1169	$ -	$ -	$ -	$ -	$ -
57	Dlvry Srvc Uncollectibles, Credit & Collections Rate $ / month	L46 / L52 / 12	($0.00)	($0.00)	($0.00)	($0.00)	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00
58	Bill Printing & Receipt Services Rate $ / month	L47 / L52 / 12	$0.58	$0.51	$0.51	$1.02	$1.02	$0.00	$0.00	$0.00	$0.00	$0.00
59	Admin $ / month	L48 / L52 / 12	$1.08	$0.66	$0.16	$4.02	$4.55	$0.00	$0.00	$0.00	$0.00	$0.00
	Delivery Service Rates and MFCs @ ROR =	**7.43%**										
60	Energy Rate (Net of MFC Supply) in $ / Mcf	L40+L41-L45 / L51b	$ 2.1512	$ 2.8621	$ 2.1036	$ 2.7049	$ 1.8845	$ -	$ -	$ -	$ -	$ -
61	Customer Rate (Net of MFC Admin) in $ / month	L55- L59	$42.60	$38.85	$40.13	$63.15	$59.34	$ -	$552.27	$ -	$356.97	$1,505.59
62	Supply Charge in $ / Mcf	L45 / L51b	$ 0.0856	$ 0.1169	$ 0.1169	$ 0.1169	$ 0.1169	$ -	$ -	$ -	$ -	$ -
63	Admin. Charge in $ / Mcf	L48 / L51b	$ 0.0677	$ 0.0924	$ 0.0924	$ 0.0924	$ 0.0924	$ -	$ -	$ -	$ -	$ -
	Current (Jul 09) Delivery Service Rates											
64	First Block			First 2 Ccf or less	$ 17.00	rst 2 Ccf or less	$ 30.00		$ 600.00	customer chg	$ 600.00	$ 600.00
65	Second Block			next 48 Ccf	$ 0.6845	next 98 Ccf	$ 0.4727		$ 9.21	Mcf of MDQ/mo	$ 7.73	$ 15.53
66	Third Block			additional gas	$ 0.3944	next 4900 Ccf	$ 0.2704		$ 1.00	Excess MDQ	$ 1.00	$ 1.00
67	Fourth Block					additional gas	$ 0.2206					

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589

Electric Revenue Allocation - Rate Year 1

Incremental Revenue Requirement Including Taxes	(1)	**$**	**11,815,000**
Taxes	(2)	**$**	**284,000**
Incremental Revenue Requirement Excluding Taxes	(3)	**$**	**11,531,000**
Percentage On Base Rates	(4)		**4.52%**

	(5) Unitized Rate of Return Embedded	(6) Unitized Rate of Return Delivery Only	(7) Unitized Rate of Return Pro Forma	(8) Revenue Allocation Factor	(9) RY Sales at Current Rates	(10)=(4)x(8)x(9) Base Rev Increase	(11) Adjustment $ 536,513	(12)=(10)+(11) Total	(13) Revenue % Increase	(14) MFC Revenue from Current Base Rates	(15) Total Estimated MFC Revenue	(16)=(14)-(15) MFC Adjustment to Rate Increase	(17)=(12)+(16) Adj Base Rev Increase	(18) Adj Increase as % of System	(19) Delivery Increase Percent
SC 1 Residential	0.77	0.74	0.99	**1.00**	$ 164,230,110	$ 7,423,073	$ 362,234	$ 7,785,307	4.74%	$ 12,334,710	$ 7,392,776	$ 4,941,934	$ 12,727,241	73.60%	8.38%
SC 2 Non Demand	(0.39)	(0.37)	(0.21)	**1.25**	$ 12,484,640	$ 705,370	$ 34,421	$ 739,791	5.93%	$ 1,399,560	$ 837,988	$ 561,572	$ 1,301,362	7.53%	11.74%
SC 2 Secondary	2.52	2.56	1.90	**0.75**	$ 53,454,240	$ 1,812,067	$ 88,426	$ 1,900,493	3.56%	$ 590,310	$ 363,296	$ 227,014	$ 2,127,507	12.30%	4.02%
SC 2 Primary	1.62	1.69	0.86	**1.00**	$ 4,848,650	$ 219,155	$ 10,694	$ 229,850	4.74%	$ 7,550	$ 5,076	$ 2,474	$ 232,323	1.34%	4.80%
SC 3 Primary	2.38	2.45	1.43	**0.75**	$ 5,860,850	$ 198,679	$ 9,695	$ 208,375	3.56%	$ -	$ -	$ -	$ 208,375	1.20%	3.56%
SC 5 Area Lighting	0.08	0.07	0.25	**1.25**	$ 1,298,523	$ 73,365	$ 3,580	$ 76,945	5.93%	$ 137,361	$ 131,372	$ 5,989	$ 82,935	0.48%	7.14%
SC 6 Residential TOU	1.50	1.47	1.34	**0.75**	$ 1,746,060	$ 59,190	$ 2,888	$ 62,079	3.56%	$ 67,580	$ 45,530	$ 22,050	$ 84,129	0.49%	5.01%
SC 8 Street Lighting	0.84	0.81	1.09	**1.00**	$ 4,282,422	$ 193,562	$ 9,446	$ 203,008	4.74%	$ 6,392	$ 5,936	$ 456	$ 203,464	1.18%	4.76%
SC 9 Traffic Signals	2.72	2.70	2.48	**0.75**	$ 201,870	$ 6,843	$ 334	$ 7,177	3.56%	$ 9,030	$ 8,525	$ 505	$ 7,682	0.04%	3.98%
SC 13 Substation	1.20	1.18	0.62	**1.00**	$ 1,999,170	$ 90,361	$ 4,409	$ 94,770	4.74%	$ -	$ -	$ -	$ 94,770	0.55%	4.74%
SC 13 Transmission	1.24	1.49	(0.11)	**1.00**	$ 4,708,490	$ 212,820	$ 10,385	$ 223,205	4.74%	$ -	$ -	$ -	$ 223,205	1.29%	4.74%
Total	1.00	1.00	1.00		$ 255,115,025	$ 10,994,487	$ 536,513	$ 11,531,000	4.52%	$ 14,552,493	$ 8,790,499	$ 5,761,994	$ 17,292,994	100%	7.19%

Electric Revenue Allocation - Rate Years 2 & 3

Rate Year 2

Incremental Revenue Requirement Including Taxes	(1)	**$**	**9,338,000**
Taxes	(2)	**$**	**225,000**
Incremental Revenue Requirement Excluding Taxes	(3)	**$**	**9,113,000**
Percentage On Base Rates	(4)		**3.43%**

	Revenue Allocation Factor	Base Rev Increase	MFC Adjustment to Rate Increase	Adj Base Rev Increase	Delivery Increase Percent
SC 1 Residential	**1.00**	$ 5,899,290	$ (81,792)	$ 5,817,498	3.56%
SC 2 Non Demand	**1.00**	$ 457,269	$ (7,036)	$ 450,233	3.63%
SC 2 Secondary	**1.00**	$ 1,910,419	$ (84)	$ 1,910,335	3.48%
SC 2 Primary	**1.00**	$ 174,872	$ (76)	$ 174,797	3.45%
SC 3 Primary	**0.75**	$ 156,406	$ -	$ 156,406	2.59%
SC 5 Area Lighting	**1.00**	$ 47,096	$ (1,281)	$ 45,815	3.71%
SC 6 Residential TOU	**1.00**	$ 62,433	$ -	$ 62,433	3.54%
SC 8 Street Lighting	**1.00**	$ 155,340	$ (13)	$ 155,327	3.46%
SC 9 Traffic Signals	**1.00**	$ 7,200	$ (50)	$ 7,151	3.57%
SC 13 Substation	**1.00**	$ 72,443	$ -	$ 72,443	3.45%
SC 13 Transmission	**1.00**	$ 170,231	$ -	$ 170,231	3.45%
Total		$ 9,113,000	$ (90,331)	$ 9,022,669	3.51%

Rate Year 3

Incremental Revenue Requirement Including Taxes	(1)	**$**	**9,054,000**
Taxes	(2)	**$**	**218,000**
Incremental Revenue Requirement Excluding Taxes	(3)	**$**	**8,836,000**
Percentage On Base Rates	(4)		**3.24%**

	Revenue Allocation Factor	Base Rev Increase	MFC Adjustment to Rate Increase	Adj Base Rev Increase	Delivery Increase Percent
SC 1 Residential	**1.00**	$ 5,702,471	$ (120,350)	$ 5,582,121	3.33%
SC 2 Non Demand	**1.00**	$ 447,326	$ (6,953)	$ 440,373	3.41%
SC 2 Secondary	**1.00**	$ 1,861,767	$ (121)	$ 1,861,645	3.28%
SC 2 Primary	**1.00**	$ 170,572	$ 8	$ 170,580	3.26%
SC 3 Primary	**0.75**	$ 151,019	$ -	$ 151,019	2.44%
SC 5 Area Lighting	**1.00**	$ 45,611	$ (1,273)	$ 44,338	3.49%
SC 6 Residential TOU	**1.00**	$ 60,945	$ -	$ 60,945	3.34%
SC 8 Street Lighting	**1.00**	$ 152,212	$ 1	$ 152,213	3.26%
SC 9 Traffic Signals	**1.00**	$ 7,030	$ 0	$ 7,030	3.39%
SC 13 Substation	**1.00**	$ 70,819	$ -	$ 70,819	3.26%
SC 13 Transmission	**1.00**	$ 166,228	$ -	$ 166,228	3.26%
Total		$ 8,836,000	$ (128,689)	$ 8,707,311	3.30%

Appendix L Sheet 2 of 3

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589

Gas Revenue Allocation - Rate Year 1

Incremental Revenue Requirement Including Taxes	(1)	**$**	**8,109,000**
Taxes	(2)	**$**	**167,000**
Incremental Revenue Requirement	(3)	**$**	**7,942,000**
Percentage On Base Rates	(4)		**13.28%**

	(5) Unitized Rate of Return Embedded	(6) Unitized Rate of Return Pro Forma	(7) Revenue Allocation Factor	(8) RY Block Revs at Current Rates	(9)=(4)x(7)x(8) Base Rev Increase	(10) Adjustment $ 20,715	(11)=(9)+(10) Total	(12) Revenue % Increase	(13) MFC Revenue from Current MFC Rates	(14) Total Estimated MFC Revenue	(15)=(13)-(14) MFC Adjustment to Rate Increase	(16)=(11)+(15) Adj Base Rev Increase	(17) Adj Increase as % of System	(18) Delivery Increase Percent
SC 1 & 12	0.88	1.04	1.00	$ 38,360,900	$ 5,094,867	$ 13,324	$ 5,108,190	13.32%	$ 2,203,910	$ 1,023,709	$ 1,180,201	$ 6,288,391	69.73%	17.39%
SC 2, 6 & 13	1.13	0.98	1.00	$ 19,436,470	$ 2,581,436	$ 6,751	$ 2,588,187	13.32%	$ 1,046,190	$ 1,150,593	$ (104,403)	$ 2,483,784	27.54%	13.51%
SC 11 Transmission	3.62	2.62	0.75	$ 1,275,720	$ 127,075	$ 332	$ 127,407	9.99%	$ -	$ -	$ -	$ 127,407	1.41%	9.99%
SC 11 Distribution	0.90	0.20	1.00	$ 72,960	$ 9,690	$ 25	$ 9,715	13.32%	$ -	$ -	$ -	$ 9,715	0.11%	13.32%
SC 11 - DLM	0.48	0.50	1.25	$ 651,840	$ 108,217	$ 283	$ 108,500	16.65%	$ -	$ -	$ -	$ 108,500	1.20%	16.65%
Total				59,797,890	$ 7,921,285	$ 20,715	$ 7,942,000		$ 3,250,100	$ 2,174,302	$ 1,075,798	$ 9,017,798	100.00%	15.95%

Gas Revenue Allocation - Rate Years 2 & 3

Rate Year 2

Incremental Revenue Requirement Including Taxes	(1)	**$**	**4,763,000**
Taxes	(2)	**$**	**69,000**
Incremental Revenue Requirement	(3)	**$**	**4,694,000**
Percentage On Base Rates	(4)		**7.11%**

	Revenue Allocation Factor	Base Rev Increase	MFC Adjustment to Rate Increase	Adj Base Rev Increase	Delivery Increase Percent
SC 1 & 12	1.00	$ 3,042,706	$ (26,218)	$ 3,032,739	7.26%
SC 2, 6 & 13	1.00	$ 1,491,586	$ 13,980	$ 1,513,532	7.64%
SC 11 Transmission	0.75	$ 74,810	$ -	$ 75,209	5.36%
SC 11 Distribution	1.00	$ 5,878	$ -	$ 5,910	7.15%
SC 11 - DLM	1.00	$ 54,084	$ -	$ 54,372	7.15%
Total		$ 4,669,063	$ (12,238)	$ 4,681,762	7.33%

Rate Year 3

Incremental Revenue Requirement Including Taxes	(1)	**$**	**4,047,000**
Taxes	(2)	**$**	**48,000**
Incremental Revenue Requirement	(3)	**$**	**3,999,000**
Percentage On Base Rates	(4)		**5.83%**

	Revenue Allocation Factor	Base Rev Increase	MFC Adjustment to Rate Increase	Adj Base Rev Increase	Delivery Increase Percent
SC 1 & 12	1.00	$ 2,588,919	$ (12,222)	$ 2,590,710	5.97%
SC 2, 6 & 13	1.00	$ 1,271,331	$ 30,413	$ 1,308,626	6.34%
SC 11 Transmission	0.75	$ 64,590	$ -	$ 64,940	4.39%
SC 11 Distribution	1.00	$ 5,166	$ -	$ 5,194	5.86%
SC 11 - DLM	1.00	$ 47,464	$ -	$ 47,721	5.86%
Total		$ 3,977,470	$ 18,191	$ 4,017,191	6.04%

Appendix L Sheet 3 of 3

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589

Gas Revenue Allocation
SC. No. 11 Phase In

SC 11 Transmission

Required Gas Rate Increases	RY1	RY2	RY3	Total
RY1	$ 127,407	$ 127,407	$ 127,407	$ 382,222
RY2	$ -	$ 75,209	$ 75,209	$ 150,418
RY3	$ -	$ -	$ 64,940	$ 64,940
Total Rate Increases	$ 127,407	$ 202,617	$ 267,557	$ 597,581
Cumulative	$ 127,407	$ 330,024	$ 597,581	
÷ 6				÷ 6
Levelized Annual Increase				$ 99,597
Levelized Gas Rate Increases	RY1	RY2	RY3	Total
RY1	$ 99,597	$ 99,597	$ 99,597	$ 298,790
RY2	$ -	$ 99,597	$ 99,597	$ 199,194
RY3	$ -	$ -	$ 99,597	$ 99,597
Total Rate Increases	$ 99,597	$ 199,194	$ 298,790	$ 597,581
Cumulative	$ 99,597	$ 298,790	$ 597,581	
Annual Shortfall	$ 27,811	$ 3,423	$ (31,234)	
Cumulative Shortfall	$ 27,811	$ 31,234	$ -	

SC 11 Distribution

Required Gas Rate Increases	RY1	RY2	RY3	Total
RY1	$ 9,715	$ 9,715	$ 9,715	$ 29,146
RY2	$ -	$ 5,910	$ 5,910	$ 11,820
RY3	$ -	$ -	$ 5,194	$ 5,194
Total Rate Increases	$ 9,715	$ 15,625	$ 20,819	$ 46,160
Cumulative	$ 9,715	$ 25,341	$ 46,160	
÷ 6				÷ 6
Levelized Annual Increase				$ 7,693
Levelized Gas Rate Increases	RY1	RY2	RY3	Total
RY1	$ 7,693	$ 7,693	$ 7,693	$ 23,080
RY2	$ -	$ 7,693	$ 7,693	$ 15,387
RY3	$ -	$ -	$ 7,693	$ 7,693
Total Rate Increases	$ 7,693	$ 15,387	$ 23,080	$ 46,160
Cumulative	$ 7,693	$ 23,080	$ 46,160	
Annual Shortfall	$ 2,022	$ 239	$ (2,261)	
Cumulative Shortfall	$ 2,022	$ 2,261	$ -	

SC 11 DLM

Required Gas Rate Increases	RY1	RY2	RY3	Total
RY1	$ 108,500	$ 108,500	$ 108,500	$ 325,500
RY2	$ -	$ 54,372	$ 54,372	$ 108,745
RY3	$ -	$ -	$ 47,721	$ 47,721
Total Rate Increases	$ 108,500	$ 162,872	$ 210,593	$ 481,966
Cumulative	$ 108,500	$ 271,372	$ 481,966	
÷ 6				÷ 6
Levelized Annual Increase				$ 80,328
Levelized Gas Rate Increases	RY1	RY2	RY3	Total
RY1	$ 80,328	$ 80,328	$ 80,328	$ 240,983
RY2	$ -	$ 80,328	$ 80,328	$ 160,655
RY3	$ -	$ -	$ 80,328	$ 80,328
Total Rate Increases	$ 80,328	$ 160,655	$ 240,983	$ 481,966
Cumulative	$ 80,328	$ 240,983	$ 481,966	
Annual Shortfall	$ 28,172	$ 2,217	$ (30,389)	
Cumulative Shortfall	$ 28,172	$ 30,389	$ -	

Appendix M Sheet 1 of 5

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Proposed Monthly Electric Base Delivery Rates
(Excludes S.C. Nos. 5 & 8)

		Current Rates	Rate Year 1 July 1, 2010	Rate Year 2 July 1, 2011	Rate Year 3 July 1, 2012
S.C. No. 1					
	Customer Charge	$ 18.00	$ 20.00	$ 22.00	$ 24.00
	kWh	$ 0.04691	$ 0.05011	$ 0.04994	$ 0.04963
S.C. No. 2 - Non-Demand					
	Customer Charge	$ 30.00	$ 32.00	$ 34.00	$ 35.00
	kWh	$ 0.00340	$ 0.00680	$ 0.00537	$ 0.00588
S.C. No. 2 - Secondary					
	Customer Charge	$ 50.00	$ 63.00	$ 73.00	$ 84.00
	kWh	$ 0.00522	$ 0.00535	$ 0.00539	$ 0.00540
	kW	$ 8.00	$ 8.00	$ 8.07	$ 8.10
S.C. No. 2 - Primary					
	Customer Charge	$ 160.00	$ 210.00	$ 260.00	$ 310.00
	kWh	$ 0.00135	$ 0.00144	$ 0.00146	$ 0.00148
	kW	$ 6.30	$ 6.46	$ 6.56	$ 6.65
S.C. No. 3					
	Customer Charge	$ 620.00	$ 1,150.00	$ 1,400.00	$ 1,400.00
	kWh	$ -	$ -	$ -	$ -
	kW	$ 8.42	$ 8.42	$ 8.51	$ 8.74
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 6					
	Customer Charge	$ 21.00	$ 23.00	$ 25.00	$ 27.00
	On-Peak kWh	$ 0.07892	$ 0.07416	$ 0.06040	
	Off-Peak kWh	$ 0.02630	$ 0.03117	$ 0.03955	
	All kWh*				$ 0.04744
S.C. No. 9 - Traffic Signals					
	Charge per Signal Face	$ 2.66	$ 2.76	$ 2.86	$ 2.96
S.C. No. 13 - Substation					
	Customer Charge	$ 800.00	$ 1,940.00	$ 2,040.00	$ 2,040.00
	kWh	$ -	$ -	$ -	$ -
	kW	$ 6.21	$ 6.21	$ 6.42	$ 6.65
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83
S.C. No. 13 - Transmission					
	Customer Charge	$ 800.00	$ 3,700.00	$ 3,810.00	$ 3,810.00
	kWh	$ -	$ -	$ -	$ -
	kW	$ 3.34	$ 3.35	$ 3.47	$ 3.59
	Rkva	$ 0.83	$ 0.83	$ 0.83	$ 0.83

*In RY3 on-/off-peak rate differential eliminated for S.C. No. 6. All kWh billed at same rate

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Proposed Electric Merchant Function Charges

	Current Rates	Rate Year 1 July 1, 2010	Rate Year 2 July 1, 2011	Rate Year 3 July 1, 2012
MFC Administration Charge per kWh				
S.C. No. 1 - Residential	$ 0.00209	$ 0.00178	$ 0.00180	$ 0.00183
S.C. No. 2 - Non Demand	$ 0.00283	$ 0.00236	$ 0.00238	$ 0.00240
S.C. No. 2 - Primary Demand	$ 0.00001	$ 0.00001	$ 0.00001	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00014	$ 0.00012	$ 0.00012	$ 0.00012
S.C. No. 3 - Large Power Primary	$ -	$ -	$ -	$ -
S.C. No. 5 - Area Lighting	$ -	$ 0.00500	$ 0.00505	$ 0.00510
S.C. No. 6 - Residential Time-of-Use	$ 0.00081	$ 0.00078	$ 0.00078	$ 0.00078
S.C. No. 8 - Street Lighting	$ -	$ 0.00013	$ 0.00013	$ 0.00013
S.C. No. 9 - Traffic Signals	$ -	$ 0.00127	$ 0.00128	$ 0.00128
S.C. No. 13 - Substation	$ -	$ -	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -	$ -	$ -
MFC Supply Charge per kWh				
S.C. No. 1 - Residential	$ 0.00390	$ 0.00181	$ 0.00183	$ 0.00186
S.C. No. 2 - Non Demand	$ 0.00512	$ 0.00240	$ 0.00242	$ 0.00244
S.C. No. 2 - Primary Demand	$ 0.00002	$ 0.00001	$ 0.00001	$ 0.00001
S.C. No. 2 - Secondary Demand	$ 0.00025	$ 0.00012	$ 0.00012	$ 0.00012
S.C. No. 3 - Large Power Primary	$ -	$ -	$ -	$ -
S.C. No. 5 - Area Lighting	$ 0.01055	$ 0.00509	$ 0.00514	$ 0.00519
S.C. No. 6 - Residential Time-of-Use	$ 0.00152	$ 0.00079	$ 0.00079	$ 0.00079
S.C. No. 8 - Street Lighting	$ 0.00028	$ 0.00013	$ 0.00013	$ 0.00013
S.C. No. 9 - Traffic Signals	$ 0.00270	$ 0.00129	$ 0.00130	$ 0.00130
S.C. No. 13 - Substation	$ -	$ -	$ -	$ -
S.C. No. 13 - Transmission	$ -	$ -	$ -	$ -

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Proposed Electric Bill Credit

		Current Rates	Rate Year 1 July 1, 2010	Rate Year 2 July 1, 2011	Rate Year 3 July 1, 2012
S.C. No. 1 - Residential	per kWh	$ (0.00682)	$ (0.00393)	$ (0.00127)	$ -
S.C. No. 2 - Non Demand	per kWh	$ (0.00658)	$ (0.00437)	$ (0.00115)	$ -
S.C. No. 2 - Primary Demand	per kWh	$ (0.00131)	$ (0.00094)	$ (0.00030)	$ -
S.C. No. 2 - Secondary Demand	per kWh	$ (0.00209)	$ (0.00131)	$ (0.00056)	$ -
S.C. No. 3 - Large Power Primary	per kW	$ (0.52)	$ (0.33)	$ (0.11)	$ -
S.C. No. 5 - Area Lighting	per kWh	$ (0.00917)	$ (0.00614)	$ (0.00163)	$ -
S.C. No. 6 - Residential Time-of-Use	per kWh	$ (0.00345)	$ (0.00224)	$ (0.00093)	$ -
S.C. No. 8 - Street Lighting	per kWh	$ (0.01185)	$ (0.00924)	$ (0.00298)	$ -
S.C. No. 9 - Traffic Signals	per kWh	$ (0.00354)	$ (0.00210)	$ (0.00091)	$ -
S.C. No. 13 - Substation	per kW	$ (0.59)	$ (0.32)	$ (0.10)	$ -
S.C. No. 13 - Transmission	per kW	$ (0.31)	$ (0.17)	$ (0.05)	$ -

Appendix M Sheet 4 of 5

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Summary of Proposed Monthly Gas Base Delivery Rates

		Current Rates	Rate Year 1 July 1, 2010	Rate Year 2 July 1, 2011	Rate Year 3 July 1, 2012	Rate Year 4 July 1, 2014 *
S.C. No. 1 & 12						
Billing Block 1	First 2 Ccf	$ 17.00	$ 19.00	$ 21.00	$ 23.00	
Billing Block 2 per Ccf	Next 48 Ccf	$ 0.6845	$ 0.8439	$ 0.8617	$ 0.8603	
Billing Block 3 per Ccf	Additional	$ 0.3944	$ 0.3944	$ 0.3944	$ 0.3944	
S.C. No. 2, 6 & 13						
Billing Block 1	First 2 Ccf	$ 30.00	$ 35.00	$ 36.50	$ 37.00	
Billing Block 2 per Ccf	Next 98 Ccf	$ 0.4727	$ 0.5572	$ 0.5604	$ 0.5494	
Billing Block 3 per Ccf	Next 4900 Ccf	$ 0.2704	$ 0.2704	$ 0.2704	$ 0.2704	
Billing Block 4 per Ccf	Additional	$ 0.2206	$ 0.2206	$ 0.2206	$ 0.2206	
S.C. No. 11 Transmission						
Customer Charge		$ 600.00	$ 800.00	$ 1,000.00	$ 1,200.00	$ 1,200.00
MDQ		$ 7.73	$ 8.30	$ 8.87	$ 9.44	$ 9.25
S.C. No. 11 Distribution						
Customer Charge		$ 600.00	$ 800.00	$ 1,000.00	$ 1,200.00	$ 1,200.00
MDQ		$ 15.53	$ 16.78	$ 18.03	$ 19.28	$ 18.75
S.C. No. 11 DLM						
Customer Charge		$ 600.00	$ 800.00	$ 1,000.00	$ 1,200.00	$ 1,200.00
MDQ		$ 9.21	$ 10.32	$ 11.43	$ 12.54	$ 12.12

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

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Gas Commodity Related Merchant Function Charges

		Current Rates	Rate Year 1 July 1, 2010	Rate Year 2 July 1, 2011	Rate Year 3 July 1, 2012
MFC Administration Charge per Ccf					
MFC-1	1, 12 & 16	$ 0.02536	$ 0.00924	$ 0.00949	$ 0.00960
MFC-2	2, 6, 13 & 15	$ 0.00372	$ 0.00920	$ 0.00909	$ 0.00886
MFC Supply Charge per Ccf					
MFC-1	1, 12 & 16	$ 0.01970	$ 0.01169	$ 0.01199	$ 0.01214
MFC-2	2, 6, 13 & 15	$ 0.01523	$ 0.01164	$ 0.01150	$ 0.01120

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Bill Impacts

S.C. No. 1 - Non Heating

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	500	540	570	600	630	660	690	720	760
Present Bill	$ 81.61	$ 86.67	$ 90.46	$ 94.25	$ 98.04	$ 101.83	$ 105.63	$ 109.42	$ 114.47
Proposed Bill - RY1	$ 85.54	$ 90.75	$ 94.65	$ 98.56	$ 102.47	$ 106.37	$ 110.28	$ 114.18	$ 119.39
$ Increase	$ 3.93	$ 4.08	$ 4.20	$ 4.31	$ 4.42	$ 4.54	$ 4.65	$ 4.76	$ 4.91
% Increase	4.82%	4.71%	4.64%	4.57%	4.51%	4.45%	4.40%	4.35%	4.29%

EBC Reduction	$ 1.48	$ 1.60	$ 1.69	$ 1.77	$ 1.86	$ 1.95	$ 2.04	$ 2.13	$ 2.25
Delivery Rate Increase	$ 2.45	$ 2.49	$ 2.51	$ 2.54	$ 2.56	$ 2.58	$ 2.61	$ 2.64	$ 2.66
Total $ Increase	$ 3.93	$ 4.08	$ 4.20	$ 4.31	$ 4.42	$ 4.54	$ 4.65	$ 4.76	$ 4.91

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	500	530	560	590	620	650	680	710	740
Present Bill - RY1	$ 85.54	$ 89.45	$ 93.35	$ 97.26	$ 101.16	$ 105.07	$ 108.97	$ 112.88	$ 116.78
Proposed Bill - RY2	$ 88.88	$ 92.86	$ 96.85	$ 100.83	$ 104.81	$ 108.80	$ 112.78	$ 116.76	$ 120.74
$ Increase	$ 3.34	$ 3.42	$ 3.49	$ 3.57	$ 3.65	$ 3.73	$ 3.81	$ 3.88	$ 3.96
% Increase	3.90%	3.82%	3.74%	3.67%	3.61%	3.55%	3.49%	3.44%	3.39%

EBC Reduction	$ 1.36	$ 1.44	$ 1.52	$ 1.61	$ 1.69	$ 1.77	$ 1.85	$ 1.93	$ 2.01
Delivery Rate Increase	$ 1.98	$ 1.97	$ 1.97	$ 1.97	$ 1.96	$ 1.96	$ 1.95	$ 1.95	$ 1.95
Total $ Increase	$ 3.34	$ 3.42	$ 3.49	$ 3.57	$ 3.65	$ 3.73	$ 3.81	$ 3.88	$ 3.96

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	490	520	550	580	610	640	670	700	730
Present Bill - RY2	$ 87.55	$ 91.54	$ 95.52	$ 99.50	$ 103.49	$ 107.47	$ 111.45	$ 115.43	$ 119.42
Proposed Bill - RY3	$ 90.11	$ 94.13	$ 98.14	$ 102.15	$ 106.17	$ 110.18	$ 114.20	$ 118.21	$ 122.22
$ Increase	$ 2.56	$ 2.59	$ 2.62	$ 2.65	$ 2.68	$ 2.71	$ 2.74	$ 2.78	$ 2.81
% Increase	2.92%	2.83%	2.74%	2.66%	2.59%	2.52%	2.46%	2.40%	2.35%

EBC Reduction	$ 0.63	$ 0.68	$ 0.72	$ 0.76	$ 0.79	$ 0.83	$ 0.87	$ 0.91	$ 0.95
Delivery Rate Increase	$ 1.92	$ 1.91	$ 1.90	$ 1.89	$ 1.89	$ 1.88	$ 1.88	$ 1.87	$ 1.86
Total $ Increase	$ 2.56	$ 2.59	$ 2.62	$ 2.65	$ 2.68	$ 2.71	$ 2.74	$ 2.78	$ 2.81

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge	$ 0.06548 per kWh		SBC/RPS	$ 0.00392
Market Price Adjustment	$ 0.00970 per kWh		NYS Assessment	$ 0.00303
Purchased Power Adjustment	$ (0.00113) per kWh		Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ (0.00231) per kWh		Revenue Tax Rate - Delivery	2.229%

Appendix N Sheet 2 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Bill Impacts (Delivery Only)

S.C. No. 1 - Non Heating

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	500	540	570	600	630	660	690	720	760
Present Bill	$ 45.66	$ 47.84	$ 49.47	$ 51.11	$ 52.74	$ 54.38	$ 56.01	$ 57.65	$ 59.83
Proposed Bill - RY1	$ 49.59	$ 51.92	$ 53.67	$ 55.42	$ 57.17	$ 58.91	$ 60.66	$ 62.41	$ 64.74
$ Increase	$ 3.93	$ 4.08	$ 4.20	$ 4.31	$ 4.42	$ 4.54	$ 4.65	$ 4.76	$ 4.91
% Increase	8.61%	8.54%	8.48%	8.43%	8.39%	8.34%	8.30%	8.26%	8.21%

EBC Reduction	$ 1.48	$ 1.60	$ 1.69	$ 1.77	$ 1.86	$ 1.95	$ 2.04	$ 2.13	$ 2.25
Delivery Rate Increase	$ 2.45	$ 2.49	$ 2.51	$ 2.54	$ 2.56	$ 2.58	$ 2.61	$ 2.64	$ 2.66
Total $ Increase	$ 3.93	$ 4.08	$ 4.20	$ 4.31	$ 4.42	$ 4.54	$ 4.65	$ 4.76	$ 4.91

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	500	530	560	590	620	650	680	710	740
Present Bill - RY1	$ 49.59	$ 51.34	$ 53.09	$ 54.83	$ 56.58	$ 58.33	$ 60.08	$ 61.83	$ 63.57
Proposed Bill - RY2	$ 52.93	$ 54.76	$ 56.58	$ 58.41	$ 60.23	$ 62.06	$ 63.88	$ 65.71	$ 67.54
$ Increase	$ 3.34	$ 3.42	$ 3.49	$ 3.57	$ 3.65	$ 3.73	$ 3.81	$ 3.88	$ 3.96
% Increase	6.73%	6.66%	6.58%	6.51%	6.45%	6.39%	6.33%	6.28%	6.23%

EBC Reduction	$ 1.36	$ 1.44	$ 1.52	$ 1.61	$ 1.69	$ 1.77	$ 1.85	$ 1.93	$ 2.01
Delivery Rate Increase	$ 1.98	$ 1.97	$ 1.97	$ 1.97	$ 1.96	$ 1.96	$ 1.95	$ 1.95	$ 1.95
Total $ Increase	$ 3.34	$ 3.42	$ 3.49	$ 3.57	$ 3.65	$ 3.73	$ 3.81	$ 3.88	$ 3.96

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	490	520	550	580	610	640	670	700	730
Present Bill - RY2	$ 52.32	$ 54.15	$ 55.97	$ 57.80	$ 59.62	$ 61.45	$ 63.28	$ 65.10	$ 66.93
Proposed Bill - RY3	$ 54.88	$ 56.74	$ 58.59	$ 60.45	$ 62.31	$ 64.16	$ 66.02	$ 67.88	$ 69.73
$ Increase	$ 2.56	$ 2.59	$ 2.62	$ 2.65	$ 2.68	$ 2.71	$ 2.74	$ 2.78	$ 2.81
% Increase	4.89%	4.78%	4.68%	4.59%	4.50%	4.42%	4.34%	4.26%	4.19%

EBC Reduction	$ 0.63	$ 0.68	$ 0.72	$ 0.76	$ 0.79	$ 0.83	$ 0.87	$ 0.91	$ 0.95
Delivery Rate Increase	$ 1.92	$ 1.91	$ 1.90	$ 1.89	$ 1.89	$ 1.88	$ 1.88	$ 1.87	$ 1.86
Total $ Increase	$ 2.56	$ 2.59	$ 2.62	$ 2.65	$ 2.68	$ 2.71	$ 2.74	$ 2.78	$ 2.81

The following rates were used in the development of these bills:

Market Price Charge	$ -	per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ -	per kWh	NYS Assessment	$ 0.00303
Purchased Power Adjustment	$ -	per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ -	per kWh	Revenue Tax Rate - Delivery	2.229%

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Bill Impacts

S.C. No. 1 - Heating

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	800	860	910	960	1,010	1,060	1,110	1,160	1,210
Present Bill	$ 119.53	$ 127.11	$ 133.43	$ 139.75	$ 146.07	$ 152.39	$ 158.71	$ 165.03	$ 171.35
Proposed Bill - RY1	$ 124.59	$ 132.41	$ 138.91	$ 145.42	$ 151.93	$ 158.44	$ 164.95	$ 171.46	$ 177.97
$ Increase	$ 5.06	$ 5.29	$ 5.48	$ 5.67	$ 5.86	$ 6.05	$ 6.23	$ 6.42	$ 6.61
% Increase	4.24%	4.16%	4.11%	4.06%	4.01%	3.97%	3.93%	3.89%	3.86%

EBC Reduction	$ 2.36	$ 2.49	$ 2.63	$ 2.78	$ 2.93	$ 3.08	$ 3.22	$ 3.37	$ 3.52
Delivery Rate Increase	$ 2.70	$ 2.81	$ 2.85	$ 2.89	$ 2.93	$ 2.97	$ 3.01	$ 3.06	$ 3.09
Total $ Increase	$ 5.06	$ 5.29	$ 5.48	$ 5.67	$ 5.86	$ 6.05	$ 6.23	$ 6.42	$ 6.61

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	800	840	890	940	990	1,040	1,090	1,140	1,190
Present Bill - RY1	$ 124.59	$ 129.80	$ 136.31	$ 142.82	$ 149.33	$ 155.84	$ 162.35	$ 168.85	$ 175.36
Proposed Bill - RY2	$ 128.71	$ 134.02	$ 140.66	$ 147.30	$ 153.94	$ 160.57	$ 167.21	$ 173.85	$ 180.49
$ Increase	$ 4.12	$ 4.22	$ 4.35	$ 4.48	$ 4.61	$ 4.74	$ 4.87	$ 5.00	$ 5.12
% Increase	3.30%	3.25%	3.19%	3.14%	3.09%	3.04%	3.00%	2.96%	2.92%

EBC Reduction	$ 2.18	$ 2.28	$ 2.42	$ 2.56	$ 2.69	$ 2.83	$ 2.97	$ 3.10	$ 3.24
Delivery Rate Increase	$ 1.94	$ 1.94	$ 1.92	$ 1.92	$ 1.92	$ 1.90	$ 1.90	$ 1.90	$ 1.88
Total $ Increase	$ 4.12	$ 4.22	$ 4.35	$ 4.48	$ 4.61	$ 4.74	$ 4.87	$ 5.00	$ 5.12

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	800	820	870	920	970	1,020	1,070	1,120	1,160
Present Bill - RY2	$ 128.71	$ 131.37	$ 138.00	$ 144.64	$ 151.28	$ 157.92	$ 164.56	$ 171.19	$ 176.50
Proposed Bill - RY3	$ 131.59	$ 134.27	$ 140.96	$ 147.65	$ 154.34	$ 161.03	$ 167.72	$ 174.41	$ 179.76
$ Increase	$ 2.88	$ 2.90	$ 2.95	$ 3.01	$ 3.06	$ 3.11	$ 3.16	$ 3.21	$ 3.26
% Increase	2.24%	2.21%	2.14%	2.08%	2.02%	1.97%	1.92%	1.88%	1.84%

EBC Reduction	$ 1.04	$ 1.09	$ 1.16	$ 1.22	$ 1.29	$ 1.35	$ 1.41	$ 1.48	$ 1.54
Delivery Rate Increase	$ 1.84	$ 1.81	$ 1.80	$ 1.79	$ 1.77	$ 1.76	$ 1.75	$ 1.73	$ 1.71
Total $ Increase	$ 2.88	$ 2.90	$ 2.95	$ 3.01	$ 3.06	$ 3.11	$ 3.16	$ 3.21	$ 3.26

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge	$ 0.06548	per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ 0.00970	per kWh	NYS Assessment	$ 0.00303
Purchased Power Adjustment	$ (0.00113)	per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ (0.00231)	per kWh	Revenue Tax Rate - Delivery	2.229%

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Bill Impacts (Delivery Only)

S.C. No. 1 - Heating

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	800	860	910	960	1,010	1,060	1,110	1,160	1,210
Present Bill	$ 62.01	$ 65.28	$ 68.00	$ 70.73	$ 73.45	$ 76.17	$ 78.90	$ 81.62	$ 84.35
Proposed Bill - RY1	$ 67.07	$ 70.57	$ 73.48	$ 76.39	$ 79.31	$ 82.22	$ 85.13	$ 88.05	$ 90.96
$ Increase	$ 5.06	$ 5.29	$ 5.48	$ 5.67	$ 5.86	$ 6.05	$ 6.23	$ 6.42	$ 6.61
% Increase	8.17%	8.11%	8.06%	8.02%	7.97%	7.94%	7.90%	7.87%	7.84%

EBC Reduction	$ 2.36	$ 2.49	$ 2.63	$ 2.78	$ 2.93	$ 3.08	$ 3.22	$ 3.37	$ 3.52
Delivery Rate Increase	$ 2.70	$ 2.81	$ 2.85	$ 2.89	$ 2.93	$ 2.97	$ 3.01	$ 3.06	$ 3.09
Total $ Increase	$ 5.06	$ 5.29	$ 5.48	$ 5.67	$ 5.86	$ 6.05	$ 6.23	$ 6.42	$ 6.61

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	800	840	890	940	990	1,040	1,090	1,140	1,190
Present Bill - RY1	$ 67.07	$ 69.40	$ 72.32	$ 75.23	$ 78.14	$ 81.06	$ 83.97	$ 86.88	$ 89.80
Proposed Bill - RY2	$ 71.19	$ 73.62	$ 76.66	$ 79.71	$ 82.75	$ 85.79	$ 88.84	$ 91.88	$ 94.92
$ Increase	$ 4.12	$ 4.22	$ 4.35	$ 4.48	$ 4.61	$ 4.74	$ 4.87	$ 5.00	$ 5.12
% Increase	6.14%	6.08%	6.01%	5.95%	5.90%	5.84%	5.80%	5.75%	5.71%

EBC Reduction	$ 2.18	$ 2.28	$ 2.42	$ 2.56	$ 2.69	$ 2.83	$ 2.97	$ 3.10	$ 3.24
Delivery Rate Increase	$ 1.94	$ 1.94	$ 1.92	$ 1.92	$ 1.92	$ 1.90	$ 1.90	$ 1.90	$ 1.88
Total $ Increase	$ 4.12	$ 4.22	$ 4.35	$ 4.48	$ 4.61	$ 4.74	$ 4.87	$ 5.00	$ 5.12

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	800	820	870	920	970	1,020	1,070	1,120	1,160
Present Bill - RY2	$ 71.19	$ 72.40	$ 75.45	$ 78.49	$ 81.53	$ 84.58	$ 87.62	$ 90.66	$ 93.10
Proposed Bill - RY3	$ 74.07	$ 75.30	$ 78.40	$ 81.49	$ 84.59	$ 87.68	$ 90.78	$ 93.87	$ 96.35
$ Increase	$ 2.88	$ 2.90	$ 2.95	$ 3.01	$ 3.06	$ 3.11	$ 3.16	$ 3.21	$ 3.26
% Increase	4.05%	4.01%	3.91%	3.83%	3.75%	3.68%	3.61%	3.55%	3.50%

EBC Reduction	$ 1.04	$ 1.09	$ 1.16	$ 1.22	$ 1.29	$ 1.35	$ 1.41	$ 1.48	$ 1.54
Delivery Rate Increase	$ 1.84	$ 1.81	$ 1.80	$ 1.79	$ 1.77	$ 1.76	$ 1.75	$ 1.73	$ 1.71
Total $ Increase	$ 2.88	$ 2.90	$ 2.95	$ 3.01	$ 3.06	$ 3.11	$ 3.16	$ 3.21	$ 3.26

The following rates were used in the development of these bills:

Market Price Charge	$ -	per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ -	per kWh	NYS Assessment	$ 0.00303
Purchased Power Adjustment	$ -	per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ -	per kWh	Revenue Tax Rate - Delivery	2.229%

Appendix N Sheet 5 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
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	400	430	450	480	500	530	550	580	600
Present Bill	$ 63.71	$ 66.24	$ 67.92	$ 70.44	$ 72.13	$ 74.65	$ 76.33	$ 78.85	$ 80.54
Proposed Bill - RY1	$ 66.69	$ 69.28	$ 71.02	$ 73.61	$ 75.34	$ 77.94	$ 79.67	$ 82.27	$ 84.00
$ Increase	$ 2.97	$ 3.05	$ 3.10	$ 3.17	$ 3.22	$ 3.29	$ 3.34	$ 3.41	$ 3.46
% Increase	4.67%	4.60%	4.56%	4.50%	4.46%	4.41%	4.37%	4.33%	4.30%
EBC Reduction	$ 0.88	$ 0.95	$ 0.99	$ 1.06	$ 1.11	$ 1.17	$ 1.22	$ 1.28	$ 1.33
Delivery Rate Increase	$ 2.09	$ 2.10	$ 2.10	$ 2.11	$ 2.10	$ 2.12	$ 2.12	$ 2.13	$ 2.13
Total $ Increase	$ 2.97	$ 3.05	$ 3.10	$ 3.17	$ 3.22	$ 3.29	$ 3.34	$ 3.41	$ 3.46

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	400	430	450	480	500	530	550	580	600
Present Bill - RY1	$ 66.69	$ 69.28	$ 71.02	$ 73.61	$ 75.34	$ 77.94	$ 79.67	$ 82.27	$ 84.00
Proposed Bill - RY2	$ 69.43	$ 72.08	$ 73.85	$ 76.50	$ 78.26	$ 80.92	$ 82.68	$ 85.33	$ 87.10
$ Increase	$ 2.74	$ 2.79	$ 2.83	$ 2.89	$ 2.92	$ 2.98	$ 3.01	$ 3.07	$ 3.11
% Increase	4.11%	4.03%	3.99%	3.92%	3.88%	3.82%	3.78%	3.73%	3.70%
EBC Reduction	$ 1.29	$ 1.38	$ 1.45	$ 1.55	$ 1.61	$ 1.71	$ 1.77	$ 1.87	$ 1.93
Delivery Rate Increase	$ 1.45	$ 1.41	$ 1.38	$ 1.33	$ 1.31	$ 1.26	$ 1.24	$ 1.19	$ 1.17
Total $ Increase	$ 2.74	$ 2.79	$ 2.83	$ 2.89	$ 2.92	$ 2.98	$ 3.01	$ 3.07	$ 3.11

Rate Year 3

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	390	420	440	470	490	510	540	560	590
Present Bill - RY2	$ 68.54	$ 71.19	$ 72.96	$ 75.61	$ 77.38	$ 79.15	$ 81.80	$ 83.57	$ 86.22
Proposed Bill - RY3	$ 70.21	$ 72.91	$ 74.71	$ 77.42	$ 79.22	$ 81.02	$ 83.72	$ 85.52	$ 88.23
$ Increase	$ 1.67	$ 1.72	$ 1.75	$ 1.80	$ 1.84	$ 1.87	$ 1.92	$ 1.96	$ 2.01
% Increase	2.43%	2.41%	2.40%	2.38%	2.37%	2.36%	2.35%	2.34%	2.33%
EBC Reduction	$ 0.46	$ 0.49	$ 0.52	$ 0.55	$ 0.58	$ 0.61	$ 0.63	$ 0.67	$ 0.69
Delivery Rate Increase	$ 1.21	$ 1.23	$ 1.23	$ 1.25	$ 1.26	$ 1.26	$ 1.29	$ 1.28	$ 1.32
Total $ Increase	$ 1.67	$ 1.72	$ 1.75	$ 1.80	$ 1.84	$ 1.87	$ 1.92	$ 1.96	$ 2.01

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge	$ 0.06548	per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ 0.00970	per kWh	NYS Assessment	$ 0.00247
Purchased Power Adjustment	$ (0.00117)	per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ (0.00231)	per kWh	Revenue Tax Rate - Delivery	0.229%

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Bill Impacts (Delivery Only)

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	400	430	450	480	500	530	550	580	600
Present Bill	$ 34.97	$ 35.34	$ 35.58	$ 35.95	$ 36.19	$ 36.56	$ 36.81	$ 37.17	$ 37.42
Proposed Bill - RY1	$ 37.94	$ 38.38	$ 38.68	$ 39.12	$ 39.41	$ 39.85	$ 40.14	$ 40.58	$ 40.88
$ Increase	$ 2.97	$ 3.05	$ 3.10	$ 3.17	$ 3.22	$ 3.29	$ 3.34	$ 3.41	$ 3.46
% Increase	8.51%	8.62%	8.70%	8.82%	8.89%	9.00%	9.07%	9.18%	9.25%

EBC Reduction	$ 0.88	$ 0.95	$ 0.99	$ 1.06	$ 1.11	$ 1.17	$ 1.22	$ 1.28	$ 1.33
Delivery Rate Increase	$ 2.09	$ 2.10	$ 2.10	$ 2.11	$ 2.10	$ 2.12	$ 2.12	$ 2.13	$ 2.13
Total $ Increase	$ 2.97	$ 3.05	$ 3.10	$ 3.17	$ 3.22	$ 3.29	$ 3.34	$ 3.41	$ 3.46

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	400	430	450	480	500	530	550	580	600
Present Bill - RY1	$ 37.94	$ 38.38	$ 38.68	$ 39.12	$ 39.41	$ 39.85	$ 40.14	$ 40.58	$ 40.88
Proposed Bill - RY2	$ 40.68	$ 41.18	$ 41.51	$ 42.00	$ 42.33	$ 42.83	$ 43.16	$ 43.65	$ 43.98
$ Increase	$ 2.74	$ 2.79	$ 2.83	$ 2.89	$ 2.92	$ 2.98	$ 3.01	$ 3.07	$ 3.11
% Increase	7.22%	7.28%	7.32%	7.38%	7.41%	7.47%	7.51%	7.56%	7.60%

EBC Reduction	$ 1.29	$ 1.38	$ 1.45	$ 1.55	$ 1.61	$ 1.71	$ 1.77	$ 1.87	$ 1.93
Delivery Rate Increase	$ 1.45	$ 1.41	$ 1.38	$ 1.33	$ 1.31	$ 1.26	$ 1.24	$ 1.19	$ 1.17
Total $ Increase	$ 2.74	$ 2.79	$ 2.83	$ 2.89	$ 2.92	$ 2.98	$ 3.01	$ 3.07	$ 3.11

Rate Year 3

	20% Below Average	15% Below Average	10% Below Average	5% Below Average	Average	5% Above Average	10% Above Average	15% Above Average	20% Above Average
kWh	390	420	440	470	490	510	540	560	590
Present Bill - RY2	$ 40.52	$ 41.01	$ 41.34	$ 41.84	$ 42.17	$ 42.50	$ 42.99	$ 43.32	$ 43.82
Proposed Bill - RY3	$ 42.18	$ 42.73	$ 43.09	$ 43.64	$ 44.00	$ 44.37	$ 44.91	$ 45.28	$ 45.83
$ Increase	$ 1.67	$ 1.72	$ 1.75	$ 1.80	$ 1.84	$ 1.87	$ 1.92	$ 1.96	$ 2.01
% Increase	4.11%	4.19%	4.24%	4.31%	4.36%	4.40%	4.47%	4.52%	4.58%

EBC Reduction	$ 0.46	$ 0.49	$ 0.52	$ 0.55	$ 0.58	$ 0.61	$ 0.63	$ 0.67	$ 0.69
Delivery Rate Increase	$ 1.21	$ 1.23	$ 1.23	$ 1.25	$ 1.26	$ 1.26	$ 1.29	$ 1.28	$ 1.32
Total $ Increase	$ 1.67	$ 1.72	$ 1.75	$ 1.80	$ 1.84	$ 1.87	$ 1.92	$ 1.96	$ 2.01

The following rates were used in the development of these bills:

Market Price Charge	$ -	per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ -	per kWh	NYS Assessment	$ 0.00247
Purchased Power Adjustment	$ -	per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ -	per kWh	Revenue Tax Rate - Delivery	0.229%

Appendix N Sheet 7 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
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	$ 133.12	$ 154.58	$ 176.04	$ 261.88	$ 304.80					
Proposed Bill - RY1	$ 146.54	$ 168.19	$ 189.83	$ 276.43	$ 319.73					
EBC Reduction	$ 0.39	$ 0.59	$ 0.78	$ 1.56	$ 1.95					
Delivery Rate Increase	$ 13.02	$ 13.01	$ 13.01	$ 12.99	$ 12.98					
Total $ Increase	$ 13.41	$ 13.60	$ 13.79	$ 14.55	$ 14.93					
Total % Increase	10.07%	8.80%	7.83%	5.56%	4.90%					
10										
Present Bill	$ 173.22	$ 194.68	$ 216.13	$ 301.97	$ 344.89					
Proposed Bill - RY1	$ 186.63	$ 208.28	$ 229.93	$ 316.52	$ 359.82					
EBC Reduction	$ 0.39	$ 0.59	$ 0.78	$ 1.56	$ 1.95					
Delivery Rate Increase	$ 13.02	$ 13.01	$ 13.01	$ 12.99	$ 12.98					
$ Increase	$ 13.41	$ 13.60	$ 13.79	$ 14.55	$ 14.93					
% Increase	7.74%	6.99%	6.38%	4.82%	4.33%					
15										
Present Bill			$ 256.23	$ 342.06	$ 384.98	$ 599.57	$ 814.16			
Proposed Bill - RY1			$ 270.02	$ 356.62	$ 399.92	$ 616.41	$ 832.91			
EBC Reduction			$ 0.78	$ 1.56	$ 1.95	$ 3.90	$ 5.85			
Delivery Rate Increase			$ 13.01	$ 12.99	$ 12.98	$ 12.94	$ 12.89			
$ Increase			$ 13.79	$ 14.55	$ 14.93	$ 16.84	$ 18.74			
% Increase			5.38%	4.25%	3.88%	2.81%	2.30%			
20										
Present Bill				$ 382.16	$ 425.07	$ 639.66	$ 854.26	$ 1,068.85		
Proposed Bill - RY1				$ 396.71	$ 440.01	$ 656.50	$ 873.00	$ 1,089.49		
EBC Reduction				$ 1.56	$ 1.95	$ 3.90	$ 5.85	$ 7.80		
Delivery Rate Increase				$ 12.99	$ 12.98	$ 12.94	$ 12.89	$ 12.85		
$ Increase				$ 14.55	$ 14.93	$ 16.84	$ 18.74	$ 20.65		
% Increase				3.81%	3.51%	2.63%	2.19%	1.93%		
30										
Present Bill					$ 505.26	$ 719.85	$ 934.44	$ 1,149.03	$ 1,578.21	
Proposed Bill - RY1					$ 520.19	$ 736.69	$ 953.18	$ 1,169.68	$ 1,602.67	
EBC Reduction					$ 1.95	$ 3.90	$ 5.85	$ 7.80	$ 11.70	
Delivery Rate Increase					$ 12.98	$ 12.94	$ 12.89	$ 12.85	$ 12.76	
$ Increase					$ 14.93	$ 16.84	$ 18.74	$ 20.65	$ 24.46	
% Increase					2.96%	2.34%	2.01%	1.80%	1.55%	
50										
Present Bill						$ 880.22	$ 1,094.81	$ 1,309.40	$ 1,738.58	$ 2,167.76
Proposed Bill - RY1						$ 897.05	$ 1,113.55	$ 1,330.05	$ 1,763.04	$ 2,196.03
EBC Reduction						$ 3.90	$ 5.85	$ 7.80	$ 11.70	$ 15.60
Delivery Rate Increase						$ 12.94	$ 12.89	$ 12.85	$ 12.76	$ 12.66
$ Increase						$ 16.84	$ 18.74	$ 20.65	$ 24.46	$ 28.26
% Increase						1.91%	1.71%	1.58%	1.41%	1.30%
100										
Present Bill						$ 1,281.13	$ 1,495.73	$ 1,710.32	$ 2,139.50	$ 2,568.68
Proposed Bill - RY1						$ 1,297.97	$ 1,514.47	$ 1,730.96	$ 2,163.96	$ 2,596.95
EBC Reduction						$ 3.90	$ 5.85	$ 7.80	$ 11.70	$ 15.60
Delivery Rate Increase						$ 12.94	$ 12.89	$ 12.85	$ 12.76	$ 12.66
$ Increase						$ 16.84	$ 18.74	$ 20.65	$ 24.46	$ 28.26
% Increase						1.31%	1.25%	1.21%	1.14%	1.10%

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge	$ 0.07381 per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ 0.00474 per kWh	NYS Assessment	$ 0.00247
Purchased Power Adjustment	$ (0.00127) per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ (0.00169) per kWh	Revenue Tax Rate - Delivery	0.229%

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
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	$ 146.54	$ 168.19	$ 189.83	$ 276.43	$ 319.73					
Proposed Bill - RY2	$ 157.31	$ 179.15	$ 201.00	$ 288.39	$ 332.09					
EBC Reduction	$ 0.38	$ 0.56	$ 0.75	$ 1.50	$ 1.88					
Delivery Rate Increase	$ 10.39	$ 10.41	$ 10.42	$ 10.46	$ 10.47					
Total $ Increase	$ 10.77	$ 10.97	$ 11.17	$ 11.96	$ 12.35					
Total % Increase	7.35%	6.52%	5.88%	4.33%	3.86%					
10										
Present Bill - RY1	$ 186.63	$ 208.28	$ 229.93	$ 316.52	$ 359.82					
Proposed Bill - RY2	$ 197.75	$ 219.60	$ 241.44	$ 328.83	$ 372.53					
EBC Reduction	$ 0.38	$ 0.56	$ 0.75	$ 1.50	$ 1.88					
Delivery Rate Increase	$ 10.74	$ 10.76	$ 10.77	$ 10.81	$ 10.82					
$ Increase	$ 11.12	$ 11.32	$ 11.52	$ 12.31	$ 12.70					
% Increase	5.96%	5.43%	5.01%	3.89%	3.53%					
15										
Present Bill - RY1			$ 270.02	$ 356.62	$ 399.92	$ 616.41	$ 832.91			
Proposed Bill - RY2			$ 281.89	$ 369.28	$ 412.97	$ 631.45	$ 849.92			
EBC Reduction			$ 0.75	$ 1.50	$ 1.88	$ 3.75	$ 5.63			
Delivery Rate Increase			$ 11.12	$ 11.16	$ 11.17	$ 11.28	$ 11.38			
$ Increase			$ 11.87	$ 12.66	$ 13.05	$ 15.03	$ 17.01			
% Increase			4.39%	3.55%	3.26%	2.44%	2.04%			
20										
Present Bill - RY1				$ 396.71	$ 440.01	$ 656.50	$ 873.00	$ 1,089.49		
Proposed Bill - RY2				$ 409.72	$ 453.41	$ 671.89	$ 890.36	$ 1,108.84		
EBC Reduction				$ 1.50	$ 1.88	$ 3.75	$ 5.63	$ 7.50		
Delivery Rate Increase				$ 11.51	$ 11.53	$ 11.64	$ 11.73	$ 11.84		
$ Increase				$ 13.01	$ 13.41	$ 15.39	$ 17.36	$ 19.34		
% Increase				3.28%	3.05%	2.34%	1.99%	1.78%		
30										
Present Bill - RY1					$ 520.19	$ 736.69	$ 953.18	$ 1,169.68	$ 1,602.67	
Proposed Bill - RY2					$ 534.30	$ 752.77	$ 971.25	$ 1,189.72	$ 1,626.68	
EBC Reduction					$ 1.88	$ 3.75	$ 5.63	$ 7.50	$ 11.25	
Delivery Rate Increase					$ 12.23	$ 12.34	$ 12.44	$ 12.55	$ 12.75	
$ Increase					$ 14.11	$ 16.09	$ 18.07	$ 20.05	$ 24.00	
% Increase					2.71%	2.18%	1.90%	1.71%	1.50%	
50										
Present Bill - RY1						$ 897.05	$ 1,113.55	$ 1,330.05	$ 1,763.04	$ 2,196.03
Proposed Bill - RY2						$ 914.54	$ 1,133.02	$ 1,351.49	$ 1,788.45	$ 2,225.40
EBC Reduction						$ 3.75	$ 5.63	$ 7.50	$ 11.25	$ 15.00
Delivery Rate Increase						$ 13.74	$ 13.84	$ 13.95	$ 14.16	$ 14.37
$ Increase						$ 17.49	$ 19.47	$ 21.45	$ 25.41	$ 29.37
% Increase						1.95%	1.75%	1.61%	1.44%	1.34%
100										
Present Bill - RY1						$ 1,297.97	$ 1,514.47	$ 1,730.96	$ 2,163.96	$ 2,596.95
Proposed Bill - RY2						$ 1,318.97	$ 1,537.45	$ 1,755.92	$ 2,192.87	$ 2,629.82
EBC Reduction						$ 3.75	$ 5.63	$ 7.50	$ 11.25	$ 15.00
Delivery Rate Increase						$ 17.25	$ 17.35	$ 17.46	$ 17.67	$ 17.88
$ Increase						$ 21.00	$ 22.98	$ 24.96	$ 28.92	$ 32.88
% Increase						1.62%	1.52%	1.44%	1.34%	1.27%

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge	$ 0.07381	per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ 0.00474	per kWh	NYS Assessment	$ 0.00247
Purchased Power Adjustment	$ (0.00127)	per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ (0.00169)	per kWh	Revenue Tax Rate - Delivery	0.229%

Appendix N Sheet 9 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Bill Impacts

S.C. No. 2 - Secondary Demand

Rate Year 3

	kWh									
kW	500	750	1,000	2,000	2,500	5,000	7,500	10,000	15,000	20,000
5										
Present Bill - RY2	$ 157.31	$ 179.15	$ 201.00	$ 288.39	$ 332.09					
Proposed Bill - RY3	$ 168.77	$ 190.76	$ 212.75	$ 300.71	$ 344.69					
EBC Reduction	$ 0.28	$ 0.42	$ 0.56	$ 1.12	$ 1.40					
Delivery Rate Increase	$ 11.18	$ 11.18	$ 11.19	$ 11.20	$ 11.20					
Total $ Increase	$ 11.46	$ 11.60	$ 11.75	$ 12.32	$ 12.60					
Total % Increase	7.29%	6.48%	5.84%	4.27%	3.80%					
10										
Present Bill - RY2	$ 197.75	$ 219.60	$ 241.44	$ 328.83	$ 372.53					
Proposed Bill - RY3	$ 209.36	$ 231.35	$ 253.34	$ 341.30	$ 385.28					
EBC Reduction	$ 0.28	$ 0.42	$ 0.56	$ 1.12	$ 1.40					
Delivery Rate Increase	$ 11.33	$ 11.33	$ 11.34	$ 11.35	$ 11.35					
$ Increase	$ 11.61	$ 11.75	$ 11.90	$ 12.47	$ 12.75					
% Increase	5.87%	5.35%	4.93%	3.79%	3.42%					
15										
Present Bill - RY2			$ 281.89	$ 369.28	$ 412.97	$ 631.45	$ 849.92			
Proposed Bill - RY3			$ 293.93	$ 381.89	$ 425.88	$ 645.78	$ 865.68			
EBC Reduction			$ 0.56	$ 1.12	$ 1.40	$ 2.80	$ 4.20			
Delivery Rate Increase			$ 11.49	$ 11.50	$ 11.50	$ 11.53	$ 11.56			
$ Increase			$ 12.05	$ 12.62	$ 12.90	$ 14.33	$ 15.76			
% Increase			4.27%	3.42%	3.12%	2.27%	1.85%			
20										
Present Bill - RY2				$ 409.72	$ 453.41	$ 671.89	$ 890.36	$ 1,108.84		
Proposed Bill - RY3				$ 422.49	$ 466.47	$ 686.37	$ 906.28	$ 1,126.18		
EBC Reduction				$ 1.12	$ 1.40	$ 2.80	$ 4.20	$ 5.60		
Delivery Rate Increase				$ 11.65	$ 11.65	$ 11.68	$ 11.71	$ 11.74		
$ Increase				$ 12.77	$ 13.05	$ 14.48	$ 15.91	$ 17.34		
% Increase				3.12%	2.88%	2.16%	1.79%	1.56%		
30										
Present Bill - RY2					$ 534.30	$ 752.77	$ 971.25	$ 1,189.72	$ 1,626.68	
Proposed Bill - RY3					$ 547.65	$ 767.56	$ 987.46	$ 1,207.36	$ 1,647.17	
EBC Reduction					$ 1.40	$ 2.80	$ 4.20	$ 5.60	$ 8.40	
Delivery Rate Increase					$ 11.96	$ 11.98	$ 12.01	$ 12.04	$ 12.10	
$ Increase					$ 13.36	$ 14.78	$ 16.21	$ 17.64	$ 20.50	
% Increase					2.50%	1.96%	1.67%	1.48%	1.26%	
50										
Present Bill - RY2						$ 914.54	$ 1,133.02	$ 1,351.49	$ 1,788.45	$ 2,225.40
Proposed Bill - RY3						$ 929.93	$ 1,149.83	$ 1,369.74	$ 1,809.54	$ 2,249.35
EBC Reduction						$ 2.80	$ 4.20	$ 5.60	$ 8.40	$ 11.20
Delivery Rate Increase						$ 12.59	$ 12.61	$ 12.64	$ 12.70	$ 12.75
$ Increase						$ 15.39	$ 16.81	$ 18.24	$ 21.10	$ 23.95
% Increase						1.68%	1.48%	1.35%	1.18%	1.08%
100										
Present Bill - RY2						$ 1,318.97	$ 1,537.45	$ 1,755.92	$ 2,192.87	$ 2,629.82
Proposed Bill - RY3						$ 1,335.86	$ 1,555.76	$ 1,775.67	$ 2,215.47	$ 2,655.28
EBC Reduction						$ 2.80	$ 4.20	$ 5.60	$ 8.40	$ 11.20
Delivery Rate Increase						$ 14.09	$ 14.12	$ 14.15	$ 14.20	$ 14.26
$ Increase						$ 16.89	$ 18.32	$ 19.75	$ 22.60	$ 25.46
% Increase						1.28%	1.19%	1.12%	1.03%	0.97%

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge	$ 0.07381 per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ 0.00474 per kWh	NYS Assessment	$ 0.00247
Purchased Power Adjustment	$ (0.00127) per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ (0.00169) per kWh	Revenue Tax Rate - Delivery	0.229%

Appendix N Sheet 10 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
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	$ 232.14	$ 252.24	$ 272.33	$ 352.73	$ 392.92					
Proposed Bill - RY1	$ 283.28	$ 303.49	$ 323.70	$ 404.55	$ 444.97					
EBC Reduction	$ 0.19	$ 0.28	$ 0.37	$ 0.74	$ 0.93					
Delivery Rate Increase	$ 50.95	$ 50.97	$ 51.00	$ 51.08	$ 51.11					
Total $ Increase	$ 51.14	$ 51.25	$ 51.37	$ 51.82	$ 52.04					
Total % Increase	22.03%	20.32%	18.86%	14.69%	13.25%					
10										
Present Bill	$ 263.71	$ 283.81	$ 303.91	$ 384.30	$ 424.50					
Proposed Bill - RY1	$ 315.65	$ 335.86	$ 356.08	$ 436.92	$ 477.34					
EBC Reduction	$ 0.19	$ 0.28	$ 0.37	$ 0.74	$ 0.93					
Delivery Rate Increase	$ 51.75	$ 51.78	$ 51.80	$ 51.88	$ 51.92					
Total $ Increase	$ 51.94	$ 52.06	$ 52.17	$ 52.62	$ 52.85					
Total % Increase	19.70%	18.34%	17.17%	13.69%	12.45%					
15										
Present Bill			$ 335.48	$ 415.87	$ 456.07	$ 657.05	$ 858.04			
Proposed Bill - RY1			$ 388.45	$ 469.29	$ 509.72	$ 711.83	$ 913.94			
EBC Reduction			$ 0.37	$ 0.74	$ 0.93	$ 1.85	$ 2.78			
Delivery Rate Increase			$ 52.60	$ 52.68	$ 52.72	$ 52.93	$ 53.12			
Total $ Increase			$ 52.97	$ 53.42	$ 53.65	$ 54.78	$ 55.90			
Total % Increase			15.79%	12.85%	11.76%	8.34%	6.52%			
20										
Present Bill				$ 447.44	$ 487.64	$ 688.63	$ 889.61	$ 1,090.60		
Proposed Bill - RY1				$ 501.67	$ 542.09	$ 744.20	$ 946.32	$ 1,148.43		
EBC Reduction				$ 0.74	$ 0.93	$ 1.85	$ 2.78	$ 3.70		
Delivery Rate Increase				$ 53.48	$ 53.52	$ 53.73	$ 53.92	$ 54.13		
Total $ Increase				$ 54.22	$ 54.45	$ 55.58	$ 56.70	$ 57.83		
Total % Increase				12.12%	11.17%	8.07%	6.37%	5.30%		
30										
Present Bill					$ 550.79	$ 751.77	$ 952.76	$ 1,153.74	$ 1,555.71	
Proposed Bill - RY1					$ 606.84	$ 808.95	$ 1,011.07	$ 1,213.18	$ 1,617.40	
EBC Reduction					$ 0.93	$ 1.85	$ 2.78	$ 3.70	$ 5.55	
Delivery Rate Increase					$ 55.12	$ 55.33	$ 55.53	$ 55.74	$ 56.14	
Total $ Increase					$ 56.05	$ 57.18	$ 58.31	$ 59.44	$ 61.69	
Total % Increase					10.18%	7.61%	6.12%	5.15%	3.97%	
50										
Present Bill						$ 878.06	$ 1,079.05	$ 1,280.03	$ 1,682.00	$ 2,083.97
Proposed Bill - RY1						$ 938.45	$ 1,140.56	$ 1,342.67	$ 1,746.90	$ 2,151.13
EBC Reduction						$ 1.85	$ 2.78	$ 3.70	$ 5.55	$ 7.40
Delivery Rate Increase						$ 58.54	$ 58.74	$ 58.94	$ 59.35	$ 59.75
Total $ Increase						$ 60.39	$ 61.52	$ 62.64	$ 64.90	$ 67.15
Total % Increase						6.88%	5.70%	4.89%	3.86%	3.22%
100										
Present Bill						$ 1,193.78	$ 1,394.77	$ 1,595.75	$ 1,997.72	$ 2,399.70
Proposed Bill - RY1						$ 1,262.19	$ 1,464.30	$ 1,666.42	$ 2,070.64	$ 2,474.87
EBC Reduction						$ 1.85	$ 2.78	$ 3.70	$ 5.55	$ 7.40
Delivery Rate Increase						$ 66.56	$ 66.75	$ 66.96	$ 67.37	$ 67.77
Total $ Increase						$ 68.41	$ 69.53	$ 70.66	$ 72.92	$ 75.17
Total % Increase						5.73%	4.99%	4.43%	3.65%	3.13%

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge	$ 0.07151	per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ 0.00562	per kWh	NYS Assessment	$ 0.00210
Purchased Power Adjustment	$ (0.00133)	per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ (0.00169)	per kWh	Revenue Tax Rate - Delivery	0.229%

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
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	$ 283.28	$ 303.49	$ 323.70	$ 404.55	$ 444.97					
Proposed Bill - RY2	$ 334.23	$ 354.60	$ 374.98	$ 456.49	$ 497.24					
EBC Reduction	$ 0.19	$ 0.28	$ 0.37	$ 0.74	$ 0.93					
Delivery Rate Increase	$ 50.76	$ 50.83	$ 50.91	$ 51.20	$ 51.34					
Total $ Increase	$ 50.95	$ 51.11	$ 51.28	$ 51.94	$ 52.27					
Total % Increase	17.98%	16.84%	15.84%	12.84%	11.75%					
10										
Present Bill - RY1	$ 315.65	$ 335.86	$ 356.08	$ 436.92	$ 477.34					
Proposed Bill - RY2	$ 367.10	$ 387.48	$ 407.85	$ 489.36	$ 530.11					
EBC Reduction	$ 0.19	$ 0.28	$ 0.37	$ 0.74	$ 0.93					
Delivery Rate Increase	$ 51.26	$ 51.33	$ 51.41	$ 51.70	$ 51.84					
Total $ Increase	$ 51.45	$ 51.61	$ 51.78	$ 52.44	$ 52.77					
Total % Increase	16.30%	15.37%	14.54%	12.00%	11.06%					
15										
Present Bill - RY1			$ 388.45	$ 469.29	$ 509.72	$ 711.83	$ 913.94			
Proposed Bill - RY2			$ 440.73	$ 522.24	$ 562.99	$ 766.76	$ 970.52			
EBC Reduction			$ 0.37	$ 0.74	$ 0.93	$ 1.85	$ 2.78			
Delivery Rate Increase			$ 51.91	$ 52.20	$ 52.34	$ 53.08	$ 53.80			
Total $ Increase			$ 52.28	$ 52.94	$ 53.27	$ 54.93	$ 56.58			
Total % Increase			13.46%	11.28%	10.45%	7.72%	6.19%			
20										
Present Bill - RY1				$ 501.67	$ 542.09	$ 744.20	$ 946.32	$ 1,148.43		
Proposed Bill - RY2				$ 555.11	$ 595.86	$ 799.63	$ 1,003.40	$ 1,207.16		
EBC Reduction				$ 0.74	$ 0.93	$ 1.85	$ 2.78	$ 3.70		
Delivery Rate Increase				$ 52.70	$ 52.84	$ 53.58	$ 54.30	$ 55.03		
Total $ Increase				$ 53.44	$ 53.77	$ 55.43	$ 57.08	$ 58.73		
Total % Increase				10.65%	9.92%	7.45%	6.03%	5.11%		
30										
Present Bill - RY1					$ 606.84	$ 808.95	$ 1,011.07	$ 1,213.18	$ 1,617.40	
Proposed Bill - RY2					$ 661.62	$ 865.38	$ 1,069.15	$ 1,272.91	$ 1,680.45	
EBC Reduction					$ 0.93	$ 1.85	$ 2.78	$ 3.70	$ 5.55	
Delivery Rate Increase					$ 53.85	$ 54.58	$ 55.30	$ 56.04	$ 57.49	
Total $ Increase					$ 54.78	$ 56.43	$ 58.08	$ 59.74	$ 63.04	
Total % Increase					9.03%	6.98%	5.74%	4.92%	3.90%	
50										
Present Bill - RY1						$ 938.45	$ 1,140.56	$ 1,342.67	$ 1,746.90	$ 2,151.13
Proposed Bill - RY2						$ 996.88	$ 1,200.65	$ 1,404.42	$ 1,811.95	$ 2,219.48
EBC Reduction						$ 1.85	$ 2.78	$ 3.70	$ 5.55	$ 7.40
Delivery Rate Increase						$ 56.58	$ 57.31	$ 58.04	$ 59.50	$ 60.96
Total $ Increase						$ 58.43	$ 60.09	$ 61.74	$ 65.05	$ 68.36
Total % Increase						6.23%	5.27%	4.60%	3.72%	3.18%
100										
Present Bill - RY1						$ 1,262.19	$ 1,464.30	$ 1,666.42	$ 2,070.64	$ 2,474.87
Proposed Bill - RY2						$ 1,325.64	$ 1,529.40	$ 1,733.17	$ 2,140.70	$ 2,548.24
EBC Reduction						$ 1.85	$ 2.78	$ 3.70	$ 5.55	$ 7.40
Delivery Rate Increase						$ 61.60	$ 62.32	$ 63.05	$ 64.51	$ 65.97
Total $ Increase						$ 63.45	$ 65.10	$ 66.75	$ 70.06	$ 73.37
Total % Increase						5.03%	4.45%	4.01%	3.38%	2.96%

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge	$ 0.07151	per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ 0.00562	per kWh	NYS Assessment	$ 0.00210
Purchased Power Adjustment	$ (0.00133)	per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ (0.00169)	per kWh	Revenue Tax Rate - Delivery	0.229%

Appendix N Sheet 12 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
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	$ 334.23	$ 354.60	$ 374.98	$ 456.49	$ 497.24					
Proposed Bill - RY3	$ 384.95	$ 405.41	$ 425.87	$ 507.69	$ 548.61					
EBC Reduction	$ 0.19	$ 0.28	$ 0.37	$ 0.74	$ 0.93					
Delivery Rate Increase	$ 50.54	$ 50.53	$ 50.52	$ 50.47	$ 50.44					
Total $ Increase	$ 50.73	$ 50.81	$ 50.89	$ 51.21	$ 51.37					
Total % Increase	15.18%	14.33%	13.57%	11.22%	10.33%					
10										
Present Bill - RY2	$ 367.10	$ 387.48	$ 407.85	$ 489.36	$ 530.11					
Proposed Bill - RY3	$ 418.28	$ 438.73	$ 459.19	$ 541.02	$ 581.93					
EBC Reduction	$ 0.19	$ 0.28	$ 0.37	$ 0.74	$ 0.93					
Delivery Rate Increase	$ 50.99	$ 50.98	$ 50.97	$ 50.92	$ 50.89					
Total $ Increase	$ 51.18	$ 51.26	$ 51.34	$ 51.66	$ 51.82					
Total % Increase	13.94%	13.23%	12.59%	10.56%	9.78%					
15										
Present Bill - RY2			$ 440.73	$ 522.24	$ 562.99	$ 766.76	$ 970.52			
Proposed Bill - RY3			$ 492.52	$ 574.35	$ 615.26	$ 819.83	$ 1,024.40			
EBC Reduction			$ 0.37	$ 0.74	$ 0.93	$ 1.85	$ 2.78			
Delivery Rate Increase			$ 51.42	$ 51.37	$ 51.34	$ 51.22	$ 51.09			
Total $ Increase			$ 51.79	$ 52.11	$ 52.27	$ 53.07	$ 53.87			
Total % Increase			11.75%	9.98%	9.28%	6.92%	5.55%			
20										
Present Bill - RY2				$ 555.11	$ 595.86	$ 799.63	$ 1,003.40	$ 1,207.16		
Proposed Bill - RY3				$ 607.67	$ 648.59	$ 853.15	$ 1,057.72	$ 1,262.29		
EBC Reduction				$ 0.74	$ 0.93	$ 1.85	$ 2.78	$ 3.70		
Delivery Rate Increase				$ 51.82	$ 51.79	$ 51.67	$ 51.54	$ 51.43		
Total $ Increase				$ 52.56	$ 52.72	$ 53.52	$ 54.32	$ 55.13		
Total % Increase				9.47%	8.85%	6.69%	5.41%	4.57%		
30										
Present Bill - RY2					$ 661.62	$ 865.38	$ 1,069.15	$ 1,272.91	$ 1,680.45	
Proposed Bill - RY3					$ 715.24	$ 919.81	$ 1,124.37	$ 1,328.94	$ 1,738.08	
EBC Reduction					$ 0.93	$ 1.85	$ 2.78	$ 3.70	$ 5.55	
Delivery Rate Increase					$ 52.69	$ 52.57	$ 52.45	$ 52.33	$ 52.08	
Total $ Increase					$ 53.62	$ 54.42	$ 55.23	$ 56.03	$ 57.63	
Total % Increase					8.10%	6.29%	5.17%	4.40%	3.43%	
50										
Present Bill - RY2						$ 996.88	$ 1,200.65	$ 1,404.42	$ 1,811.95	$ 2,219.48
Proposed Bill - RY3						$ 1,053.11	$ 1,257.68	$ 1,462.25	$ 1,871.39	$ 2,280.52
EBC Reduction						$ 1.85	$ 2.78	$ 3.70	$ 5.55	$ 7.40
Delivery Rate Increase						$ 54.38	$ 54.25	$ 54.13	$ 53.89	$ 53.64
Total $ Increase						$ 56.23	$ 57.03	$ 57.83	$ 59.44	$ 61.04
Total % Increase						5.64%	4.75%	4.12%	3.28%	2.75%
100										
Present Bill - RY2						$ 1,325.64	$ 1,529.40	$ 1,733.17	$ 2,140.70	$ 2,548.24
Proposed Bill - RY3						$ 1,386.37	$ 1,590.94	$ 1,795.51	$ 2,204.65	$ 2,613.79
EBC Reduction						$ 1.85	$ 2.78	$ 3.70	$ 5.55	$ 7.40
Delivery Rate Increase						$ 58.89	$ 58.76	$ 58.64	$ 58.40	$ 58.15
Total $ Increase						$ 60.74	$ 61.54	$ 62.34	$ 63.95	$ 65.55
Total % Increase						4.58%	4.02%	3.60%	2.99%	2.57%

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge	$ 0.07151	per kWh	SBC/RPS	$ 0.00392
Market Price Adjustment	$ 0.00562	per kWh	NYS Assessment	$ 0.00210
Purchased Power Adjustment	$ (0.00133)	per kWh	Revenue Tax Rate - Commodity	0.229%
Miscellaneous Charges	$ (0.00169)	per kWh	Revenue Tax Rate - Delivery	0.229%

Appendix N Sheet 13 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Bill Impacts

S.C. No. 6 - Residential Time-of-Use

Rate Year 1

	kWh								
	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
% On-Peak	1,220	1,300	1,380	1,450	1,530	1,610	1,680	1,760	1,840
40%									
Present Bill	$ 172.41	$ 182.30	$ 192.20	$ 200.86	$ 210.76	$ 220.65	$ 229.31	$ 239.21	$ 249.11
Proposed Bill - RY1	$ 176.29	$ 186.30	$ 196.32	$ 205.09	$ 215.10	$ 225.12	$ 233.88	$ 243.90	$ 253.92
EBC Reduction	$ 1.51	$ 1.61	$ 1.71	$ 1.79	$ 1.89	$ 1.99	$ 2.08	$ 2.18	$ 2.28
Delivery Rate Increase	$ 2.37	$ 2.39	$ 2.41	$ 2.44	$ 2.45	$ 2.47	$ 2.49	$ 2.51	$ 2.53
Total $ Increase	$ 3.88	$ 4.00	$ 4.12	$ 4.22	$ 4.35	$ 4.47	$ 4.57	$ 4.69	$ 4.81
Total % Increase	2.25%	2.19%	2.14%	2.10%	2.06%	2.02%	1.99%	1.96%	1.93%
35%									
Present Bill	$ 167.73	$ 177.32	$ 186.91	$ 195.30	$ 204.89	$ 214.48	$ 222.87	$ 232.46	$ 242.05
Proposed Bill - RY1	$ 172.21	$ 181.96	$ 191.71	$ 200.24	$ 209.99	$ 219.74	$ 228.27	$ 238.02	$ 247.77
EBC Reduction	$ 1.51	$ 1.61	$ 1.71	$ 1.79	$ 1.89	$ 1.99	$ 2.08	$ 2.18	$ 2.28
Delivery Rate Increase	$ 2.97	$ 3.03	$ 3.09	$ 3.15	$ 3.21	$ 3.26	$ 3.32	$ 3.38	$ 3.44
$ Increase	$ 4.48	$ 4.64	$ 4.80	$ 4.94	$ 5.10	$ 5.26	$ 5.40	$ 5.56	$ 5.72
% Increase	2.67%	2.62%	2.57%	2.53%	2.49%	2.45%	2.42%	2.39%	2.36%
30%									
Present Bill	$ 163.05	$ 172.33	$ 181.61	$ 189.73	$ 199.02	$ 208.30	$ 216.42	$ 225.71	$ 234.99
Proposed Bill - RY1	$ 168.13	$ 177.61	$ 187.09	$ 195.39	$ 204.87	$ 214.35	$ 222.65	$ 232.13	$ 241.61
EBC Reduction	$ 1.51	$ 1.61	$ 1.71	$ 1.79	$ 1.89	$ 1.99	$ 2.08	$ 2.18	$ 2.28
Delivery Rate Increase	$ 3.57	$ 3.67	$ 3.77	$ 3.86	$ 3.96	$ 4.06	$ 4.15	$ 4.25	$ 4.34
$ Increase	$ 5.08	$ 5.28	$ 5.48	$ 5.65	$ 5.85	$ 6.05	$ 6.23	$ 6.42	$ 6.62
% Increase	3.12%	3.06%	3.02%	2.98%	2.94%	2.91%	2.88%	2.85%	2.82%
25%									
Present Bill	$ 158.37	$ 167.34	$ 176.32	$ 184.17	$ 193.15	$ 202.12	$ 209.98	$ 218.95	$ 227.93
Proposed Bill - RY1	$ 164.05	$ 173.26	$ 182.48	$ 190.54	$ 199.75	$ 208.97	$ 217.03	$ 226.25	$ 235.46
EBC Reduction	$ 1.51	$ 1.61	$ 1.71	$ 1.79	$ 1.89	$ 1.99	$ 2.08	$ 2.18	$ 2.28
Delivery Rate Increase	$ 4.17	$ 4.31	$ 4.45	$ 4.58	$ 4.71	$ 4.85	$ 4.98	$ 5.11	$ 5.25
$ Increase	$ 5.68	$ 5.92	$ 6.16	$ 6.37	$ 6.61	$ 6.84	$ 7.05	$ 7.29	$ 7.53
% Increase	3.59%	3.54%	3.49%	3.46%	3.42%	3.39%	3.36%	3.33%	3.30%
20%									
Present Bill	$ 153.68	$ 162.35	$ 171.02	$ 178.61	$ 187.28	$ 195.95	$ 203.53	$ 212.20	$ 220.87
Proposed Bill - RY1	$ 159.97	$ 168.91	$ 177.86	$ 185.69	$ 194.64	$ 203.58	$ 211.41	$ 220.36	$ 229.31
EBC Reduction	$ 1.51	$ 1.61	$ 1.71	$ 1.79	$ 1.89	$ 1.99	$ 2.08	$ 2.18	$ 2.28
Delivery Rate Increase	$ 4.77	$ 4.96	$ 5.13	$ 5.29	$ 5.47	$ 5.64	$ 5.80	$ 5.98	$ 6.16
$ Increase	$ 6.28	$ 6.56	$ 6.84	$ 7.08	$ 7.36	$ 7.64	$ 7.88	$ 8.16	$ 8.44
% Increase	4.09%	4.04%	4.00%	3.97%	3.93%	3.90%	3.87%	3.84%	3.82%
10%									
Present Bill	$ 144.32	$ 152.38	$ 160.43	$ 167.48	$ 175.54	$ 183.59	$ 190.64	$ 198.70	$ 206.75
Proposed Bill - RY1	$ 151.81	$ 160.22	$ 168.63	$ 175.99	$ 184.40	$ 192.82	$ 200.18	$ 208.59	$ 217.00
EBC Reduction	$ 1.51	$ 1.61	$ 1.71	$ 1.79	$ 1.89	$ 1.99	$ 2.08	$ 2.18	$ 2.28
Delivery Rate Increase	$ 5.97	$ 6.24	$ 6.49	$ 6.72	$ 6.98	$ 7.23	$ 7.46	$ 7.71	$ 7.97
$ Increase	$ 7.49	$ 7.84	$ 8.20	$ 8.51	$ 8.87	$ 9.22	$ 9.54	$ 9.89	$ 10.25
% Increase	5.19%	5.15%	5.11%	5.08%	5.05%	5.02%	5.00%	4.98%	4.96%

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge - On-Peak	$ 0.07719	per kWh	SBC/RPS	$ 0.00392
Market Price Charge - Off-Peak	$ 0.05679	per kWh	NYS Assessment	$ 0.00240
Market Price Adjustment - On-Peak	$ 0.00928	per kWh		
Market Price Adjustment - Off-Peak	$ 0.00682	per kWh	Revenue Tax Rate - Commodity	0.229%
Purchased Power Adjustment	$ (0.00133)	per kWh	Revenue Tax Rate - Delivery	2.229%
Miscellaneous Charges	$ (0.00169)	per kWh		

Appendix N Sheet 14 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Bill Impacts

S.C. No. 6 - Residential Time-of-Use

Rate Year 2

	kWh								
	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
% On-Peak	1,220	1,300	1,380	1,450	1,530	1,610	1,680	1,760	1,840
40%									
Present Bill - RY1	$ 176.29	$ 186.30	$ 196.32	$ 205.09	$ 215.10	$ 225.12	$ 233.88	$ 243.90	$ 253.92
Proposed Bill - RY2	$ 179.37	$ 189.46	$ 199.54	$ 208.37	$ 218.45	$ 228.54	$ 237.36	$ 247.45	$ 257.53
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 1.45	$ 1.41	$ 1.37	$ 1.34	$ 1.30	$ 1.26	$ 1.23	$ 1.18	$ 1.15
Total $ Increase	$ 3.08	$ 3.15	$ 3.22	$ 3.28	$ 3.35	$ 3.42	$ 3.48	$ 3.54	$ 3.61
Total % Increase	1.75%	1.69%	1.64%	1.60%	1.56%	1.52%	1.49%	1.45%	1.42%
35%									
Present Bill - RY1	$ 172.21	$ 181.96	$ 191.71	$ 200.24	$ 209.99	$ 219.74	$ 228.27	$ 238.02	$ 247.77
Proposed Bill - RY2	$ 176.67	$ 186.58	$ 196.49	$ 205.16	$ 215.07	$ 224.98	$ 233.65	$ 243.55	$ 253.46
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 2.83	$ 2.89	$ 2.93	$ 2.98	$ 3.03	$ 3.08	$ 3.13	$ 3.17	$ 3.23
$ Increase	$ 4.47	$ 4.62	$ 4.78	$ 4.92	$ 5.08	$ 5.24	$ 5.38	$ 5.54	$ 5.70
% Increase	2.59%	2.54%	2.49%	2.46%	2.42%	2.38%	2.36%	2.33%	2.30%
30%									
Present Bill - RY1	$ 168.13	$ 177.61	$ 187.09	$ 195.39	$ 204.87	$ 214.35	$ 222.65	$ 232.13	$ 241.61
Proposed Bill - RY2	$ 173.97	$ 183.71	$ 193.44	$ 201.95	$ 211.68	$ 221.41	$ 229.93	$ 239.66	$ 249.39
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 4.21	$ 4.36	$ 4.49	$ 4.62	$ 4.77	$ 4.90	$ 5.03	$ 5.17	$ 5.31
$ Increase	$ 5.85	$ 6.10	$ 6.35	$ 6.56	$ 6.81	$ 7.06	$ 7.28	$ 7.53	$ 7.78
% Increase	3.48%	3.43%	3.39%	3.36%	3.33%	3.29%	3.27%	3.24%	3.22%
25%									
Present Bill - RY1	$ 164.05	$ 173.26	$ 182.48	$ 190.54	$ 199.75	$ 208.97	$ 217.03	$ 226.25	$ 235.46
Proposed Bill - RY2	$ 171.28	$ 180.83	$ 190.38	$ 198.74	$ 208.30	$ 217.85	$ 226.21	$ 235.77	$ 245.32
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 5.59	$ 5.83	$ 6.06	$ 6.26	$ 6.50	$ 6.73	$ 6.93	$ 7.16	$ 7.40
$ Increase	$ 7.23	$ 7.57	$ 7.91	$ 8.20	$ 8.54	$ 8.88	$ 9.18	$ 9.52	$ 9.86
% Increase	4.41%	4.37%	4.33%	4.31%	4.28%	4.25%	4.23%	4.21%	4.19%
20%									
Present Bill - RY1	$ 159.97	$ 168.91	$ 177.86	$ 185.69	$ 194.64	$ 203.58	$ 211.41	$ 220.36	$ 229.31
Proposed Bill - RY2	$ 168.58	$ 177.95	$ 187.33	$ 195.54	$ 204.91	$ 214.29	$ 222.50	$ 231.87	$ 241.25
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 6.97	$ 7.30	$ 7.62	$ 7.90	$ 8.23	$ 8.55	$ 8.83	$ 9.15	$ 9.48
$ Increase	$ 8.61	$ 9.04	$ 9.47	$ 9.85	$ 10.28	$ 10.71	$ 11.08	$ 11.51	$ 11.94
% Increase	5.38%	5.35%	5.32%	5.30%	5.28%	5.26%	5.24%	5.23%	5.21%
10%									
Present Bill - RY1	$ 151.81	$ 160.22	$ 168.63	$ 175.99	$ 184.40	$ 192.82	$ 200.18	$ 208.59	$ 217.00
Proposed Bill - RY2	$ 163.18	$ 172.20	$ 181.23	$ 189.12	$ 198.15	$ 207.17	$ 215.07	$ 224.09	$ 233.11
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 9.73	$ 10.24	$ 10.74	$ 11.19	$ 11.70	$ 12.19	$ 12.64	$ 13.14	$ 13.65
$ Increase	$ 11.37	$ 11.98	$ 12.59	$ 13.13	$ 13.74	$ 14.35	$ 14.89	$ 15.50	$ 16.11
% Increase	7.49%	7.48%	7.47%	7.46%	7.45%	7.44%	7.44%	7.43%	7.42%

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge - On-Peak	$ 0.07719	per kWh	SBC/RPS	$ 0.00392
Market Price Charge - Off-Peak	$ 0.05679	per kWh	NYS Assessment	$ 0.00240
Market Price Adjustment - On-Peak	$ 0.00928	per kWh		
Market Price Adjustment - Off-Peak	$ 0.00682	per kWh	Revenue Tax Rate - Commodity	0.229%
Purchased Power Adjustment	$ (0.00133)	per kWh	Revenue Tax Rate - Delivery	2.229%
Miscellaneous Charges	$ (0.00169)	per kWh		

Appendix N Sheet 15 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric Bill Impacts

S.C. No. 6 - Residential Time-of-Use

Rate Year 3

	kWh								
	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
% On-Peak	1,220	1,300	1,380	1,450	1,530	1,610	1,680	1,760	1,840
40%									
Present Bill - RY2	$ 179.37	$ 189.46	$ 199.54	$ 208.37	$ 218.45	$ 228.54	$ 237.36	$ 247.45	$ 257.53
Proposed Bill - RY3	$ 182.02	$ 192.14	$ 202.26	$ 211.12	$ 221.25	$ 231.37	$ 240.23	$ 250.36	$ 260.48
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 1.01	$ 0.95	$ 0.87	$ 0.81	$ 0.75	$ 0.68	$ 0.62	$ 0.55	$ 0.48
Total $ Increase	$ 2.64	$ 2.68	$ 2.72	$ 2.76	$ 2.80	$ 2.84	$ 2.87	$ 2.91	$ 2.95
Total % Increase	1.47%	1.42%	1.36%	1.32%	1.28%	1.24%	1.21%	1.18%	1.15%
35%									
Present Bill - RY2	$ 176.67	$ 186.58	$ 196.49	$ 205.16	$ 215.07	$ 224.98	$ 233.65	$ 243.55	$ 253.46
Proposed Bill - RY3	$ 180.62	$ 190.65	$ 200.68	$ 209.46	$ 219.50	$ 229.53	$ 238.31	$ 248.34	$ 258.37
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 2.31	$ 2.33	$ 2.34	$ 2.36	$ 2.38	$ 2.39	$ 2.41	$ 2.42	$ 2.45
$ Increase	$ 3.95	$ 4.07	$ 4.19	$ 4.30	$ 4.43	$ 4.55	$ 4.66	$ 4.79	$ 4.91
% Increase	2.23%	2.18%	2.13%	2.10%	2.06%	2.02%	2.00%	1.97%	1.94%
30%									
Present Bill - RY2	$ 173.97	$ 183.71	$ 193.44	$ 201.95	$ 211.68	$ 221.41	$ 229.93	$ 239.66	$ 249.39
Proposed Bill - RY3	$ 179.22	$ 189.16	$ 199.10	$ 207.80	$ 217.74	$ 227.68	$ 236.38	$ 246.32	$ 256.26
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 3.61	$ 3.72	$ 3.81	$ 3.91	$ 4.01	$ 4.11	$ 4.20	$ 4.30	$ 4.41
$ Increase	$ 5.25	$ 5.46	$ 5.67	$ 5.85	$ 6.06	$ 6.27	$ 6.45	$ 6.66	$ 6.87
% Increase	3.02%	2.97%	2.93%	2.90%	2.86%	2.83%	2.81%	2.78%	2.76%
25%									
Present Bill - RY2	$ 171.28	$ 180.83	$ 190.38	$ 198.74	$ 208.30	$ 217.85	$ 226.21	$ 235.77	$ 245.32
Proposed Bill - RY3	$ 177.82	$ 187.67	$ 197.52	$ 206.14	$ 215.99	$ 225.84	$ 234.46	$ 244.31	$ 254.16
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 4.91	$ 5.10	$ 5.29	$ 5.45	$ 5.65	$ 5.83	$ 5.99	$ 6.18	$ 6.37
$ Increase	$ 6.55	$ 6.84	$ 7.14	$ 7.40	$ 7.69	$ 7.99	$ 8.24	$ 8.54	$ 8.83
% Increase	3.82%	3.78%	3.75%	3.72%	3.69%	3.67%	3.64%	3.62%	3.60%
20%									
Present Bill - RY2	$ 168.58	$ 177.95	$ 187.33	$ 195.54	$ 204.91	$ 214.29	$ 222.50	$ 231.87	$ 241.25
Proposed Bill - RY3	$ 176.42	$ 186.18	$ 195.94	$ 204.48	$ 214.24	$ 223.99	$ 232.53	$ 242.29	$ 252.05
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 6.21	$ 6.49	$ 6.76	$ 7.00	$ 7.28	$ 7.54	$ 7.79	$ 8.05	$ 8.33
$ Increase	$ 7.85	$ 8.23	$ 8.61	$ 8.94	$ 9.32	$ 9.70	$ 10.04	$ 10.42	$ 10.80
% Increase	4.66%	4.62%	4.60%	4.57%	4.55%	4.53%	4.51%	4.49%	4.48%
10%									
Present Bill - RY2	$ 163.18	$ 172.20	$ 181.23	$ 189.12	$ 198.15	$ 207.17	$ 215.07	$ 224.09	$ 233.11
Proposed Bill - RY3	$ 173.63	$ 183.20	$ 192.78	$ 201.16	$ 210.73	$ 220.31	$ 228.68	$ 238.26	$ 247.83
EBC Reduction	$ 1.64	$ 1.74	$ 1.85	$ 1.94	$ 2.05	$ 2.16	$ 2.25	$ 2.36	$ 2.46
Delivery Rate Increase	$ 8.81	$ 9.26	$ 9.70	$ 10.09	$ 10.54	$ 10.98	$ 11.37	$ 11.81	$ 12.26
$ Increase	$ 10.45	$ 11.00	$ 11.55	$ 12.03	$ 12.59	$ 13.14	$ 13.62	$ 14.17	$ 14.72
% Increase	6.40%	6.39%	6.37%	6.36%	6.35%	6.34%	6.33%	6.32%	6.31%

The following rates were used in the development of these bills:
Commodity rates estimated at factors effective January 14, 2010

Market Price Charge - On-Peak	$ 0.07719	per kWh	SBC/RPS	$ 0.00392
Market Price Charge - Off-Peak	$ 0.05679	per kWh	NYS Assessment	$ 0.00240
Market Price Adjustment - On-Peak	$ 0.00928	per kWh		
Market Price Adjustment - Off-Peak	$ 0.00682	per kWh	Revenue Tax Rate - Commodity	0.229%
Purchased Power Adjustment	$ (0.00133)	per kWh	Revenue Tax Rate - Delivery	2.229%
Miscellaneous Charges	$ (0.00169)	per kWh		

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Gas Bills Impacts
Rate Year 1 (Twelve Months Ended June 30, 2011)

Service Classification Nos. 1 & 12

Monthly Usage Ccf	Monthly Bill Present	Monthly Bill Proposed - RY 1	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 19.23	$ 21.23	$ 2.00	10.41%
4	22.43	24.71	2.28	10.16%
6	25.62	28.18	2.56	9.98%
8	28.82	31.66	2.83	9.83%
10	32.02	35.13	3.11	9.72%
15	40.01	43.82	3.81	9.51%
20	48.00	52.50	4.50	9.37%
25	56.00	61.19	5.19	9.27%
30	63.99	69.88	5.89	9.20%
35	71.98	78.56	6.58	9.14%
40	79.97	87.25	7.27	9.10%
50	95.96	104.62	8.66	9.03%
60	108.97	117.38	8.41	7.72%
80	134.99	142.91	7.92	5.87%
100	161.01	168.43	7.42	4.61%
130	200.03	206.72	6.68	3.34%
170	252.07	257.76	5.69	2.26%
200	291.10	296.05	4.95	1.70%
300	421.19	423.66	2.47	0.59%
1000	1,331.84	1,316.99	(14.85)	-1.12%
Average Annual Heating Customer @ 910 Ccf Per Year				
910	1,507.48	1,577.76	70.28	4.66%

Weighted Revenue Tax Factor:	Delivery		0.02513
	Commodity		0.00513
Gas Supply Charge Factors Effective 2/2/10 (per Ccf):			$ 0.80960
New York State Assessment Surcharge:			$ 0.03289

Merchant Function Charge (per Ccf):		Present	Proposed
	MFC Admin	$ 0.02536	$ 0.00924
	MFC Supply	$ 0.02144	$ 0.01343
	Transition Adj.	$ 0.00148	$ 0.00148

S.C. No. 1 & 12 Base Delivery Rates		Present	Proposed - RY 1
Block 1	First 2 Ccf	$ 17.00	$ 19.00
Block 2 per Ccf	Next 48 Ccf	$ 0.6845	$ 0.8439
Block 3 per Ccf	Additional	$ 0.3944	$ 0.3944

Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Monthly Bill Present	Monthly Bill Proposed - RY 1	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 31.90	$ 36.93	$ 5.03	15.77%
10	42.67	48.39	5.72	13.41%
30	69.60	77.06	7.46	10.72%
50	96.54	105.73	9.20	9.53%
100	163.87	177.41	13.54	8.26%
150	221.03	234.67	13.63	6.17%
200	278.20	291.93	13.73	4.94%
250	335.36	349.18	13.82	4.12%
300	392.52	406.44	13.92	3.55%
400	506.85	520.96	14.11	2.78%
500	621.18	635.48	14.30	2.30%
600	735.51	750.00	14.49	1.97%
800	964.17	979.04	14.87	1.54%
1000	1,192.82	1,208.07	15.25	1.28%
1500	1,764.47	1,780.67	16.20	0.92%
2000	2,336.11	2,353.26	17.15	0.73%
3000	3,479.39	3,498.44	19.05	0.55%
5000	5,765.96	5,788.81	22.85	0.40%
7500	8,499.03	8,526.63	27.60	0.32%
10000	11,232.11	11,264.45	32.35	0.29%
12000	13,418.56	13,454.71	36.15	0.27%
14000	15,605.02	15,644.96	39.95	0.26%
16000	17,791.47	17,835.22	43.75	0.25%
20000	22,164.39	22,215.73	51.34	0.23%
Average Annual Heating Customer @ 5220 Ccf Per Year				
5220	6,562.41	6,732.52	170.11	2.59%

Weighted Revenue Tax Factor:	Delivery		0.00513
	Commodity		0.00513
Gas Supply Charge Factors Effective 2/2/10 (per Ccf):			$ 0.80960
New York State Assessment Surcharge:			$ 0.02708

Merchant Function Charge (per Ccf):		Present	Proposed
	MFC Admin	$ 0.00372	$ 0.00920
	MFC Supply	$ 0.02282	$ 0.01923
	Transition Adj.	$ 0.00380	$ 0.00380

S.C. No. 2, 6 & 13 Base Delivery Rates		Present	Proposed - RY 1
Block 1	First 2 Ccf	$ 30.00	$ 35.00
Block 2 per Ccf	Next 98 Ccf	$ 0.4727	$ 0.5572
Block 3 per Ccf	Next 4900 Ccf	$ 0.2704	$ 0.2704
Block 4 per Ccf	Additional	$ 0.2206	$ 0.2206

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Gas Bills Impacts (Delivery Only)
Rate Year 1 (Twelve Months Ended June 30, 2011)

Service Classification Nos. 1 & 12

Monthly Usage Ccf	Monthly Bill Present	Monthly Bill Proposed - RY 1	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 17.60	$ 19.61	$ 2.00	11.37%
4	19.17	21.45	2.28	11.89%
6	20.74	23.30	2.56	12.33%
8	22.31	25.15	2.83	12.70%
10	23.88	26.99	3.11	13.03%
15	27.80	31.61	3.81	13.69%
20	31.73	36.23	4.50	14.18%
25	35.65	40.85	5.19	14.57%
30	39.58	45.46	5.89	14.88%
35	43.50	50.08	6.58	15.13%
40	47.42	54.70	7.27	15.34%
50	55.27	63.93	8.66	15.67%
60	60.14	68.56	8.41	13.99%
80	69.88	77.80	7.92	11.33%
100	79.63	87.05	7.42	9.32%
130	94.24	100.92	6.68	7.09%
170	113.73	119.42	5.69	5.01%
200	128.34	133.29	4.95	3.86%
300	177.06	179.53	2.47	1.40%
1000	518.06	503.21	(14.85)	-2.87%
Average Annual Heating Customer @ 910 Ccf Per Year				
910	766.95	837.22	70.28	9.16%

Weighted Revenue Tax Factor:		Delivery	0.02513
		Commodity	0.00513
New York State Assessment Surcharge:			$ 0.03289
Merchant Function Charge (per Ccf):		Present	Proposed
	MFC Admin	$ 0.02536	$ 0.00924
	MFC Supply	$ 0.02144	$ 0.01343
	Transition Adj.	$ 0.00148	$ 0.00148

S.C. No. 1 & 12 Base Delivery Rates		Present	Proposed - RY 1
Block 1	First 2 Ccf	$ 17.00	$ 19.00
Block 2 per Ccf	Next 48 Ccf	$ 0.6845	$ 0.8439
Block 3 per Ccf	Additional	$ 0.3944	$ 0.3944

Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Monthly Bill Present	Monthly Bill Proposed - RY 1	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 30.27	$ 35.30	$ 5.03	16.62%
10	34.53	40.26	5.72	16.58%
30	45.19	52.65	7.46	16.51%
50	55.85	65.04	9.20	16.47%
100	82.49	96.03	13.54	16.41%
150	98.97	112.60	13.63	13.78%
200	115.44	129.17	13.73	11.89%
250	131.92	145.74	13.82	10.48%
300	148.39	162.31	13.92	9.38%
400	181.34	195.45	14.11	7.78%
500	214.29	228.59	14.30	6.67%
600	247.24	261.73	14.49	5.86%
800	313.15	328.02	14.87	4.75%
1000	379.05	394.30	15.25	4.02%
1500	543.80	560.00	16.20	2.98%
2000	708.56	725.71	17.15	2.42%
3000	1,038.07	1,057.12	19.05	1.84%
5000	1,697.09	1,719.94	22.85	1.35%
7500	2,395.72	2,423.32	27.60	1.15%
10000	3,094.36	3,126.71	32.35	1.05%
12000	3,653.27	3,689.41	36.15	0.99%
14000	4,212.17	4,252.12	39.95	0.95%
16000	4,771.08	4,814.83	43.75	0.92%
20000	5,888.89	5,940.24	51.34	0.87%
Average Annual Heating Customer @ 5220 Ccf Per Year				
5220	2,314.51	2,484.62	170.11	7.35%

Weighted Revenue Tax Factor:		Delivery	0.00513
		Commodity	0.00513
New York State Assessment Surcharge:			$ 0.02708
Merchant Function Charge (per Ccf):		Present	Proposed
	MFC Admin	$ 0.00372	$ 0.00920
	MFC Supply	$ 0.02282	$ 0.01923
	Transition Adj.	$ 0.00380	$ 0.00380

S.C. No. 2, 6 & 13 Base Delivery Rates		Present	Proposed - RY 1
Block 1	First 2 Ccf	$ 30.00	$ 35.00
Block 2 per Ccf	Next 98 Ccf	$ 0.4727	$ 0.5572
Block 3 per Ccf	Next 4900 Ccf	$ 0.2704	$ 0.2704
Block 4 per Ccf	Additional	$ 0.2206	$ 0.2206

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Gas Bills Impacts
Rate Year 2 (Twelve Months Ended June 30, 2012)

Service Classification Nos. 1 & 12

Monthly Usage Ccf	Monthly Bill Present - RY 1	Monthly Bill Proposed - RY 2	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 21.23	$ 23.29	$ 2.05	9.67%
4	24.71	26.80	2.09	8.46%
6	28.18	30.31	2.13	7.55%
8	31.66	33.82	2.17	6.84%
10	35.13	37.33	2.20	6.27%
15	43.82	46.11	2.30	5.24%
20	52.50	54.90	2.39	4.55%
25	61.19	63.68	2.49	4.06%
30	69.88	72.46	2.58	3.69%
35	78.56	81.24	2.67	3.40%
40	87.25	90.02	2.77	3.17%
50	104.62	107.58	2.96	2.83%
60	117.38	120.35	2.96	2.52%
80	142.91	145.88	2.97	2.08%
100	168.43	171.41	2.98	1.77%
130	206.72	209.72	3.00	1.45%
170	257.76	260.79	3.02	1.17%
200	296.05	299.09	3.04	1.03%
300	423.66	426.76	3.10	0.73%
1000	1,316.99	1,320.48	3.49	0.27%
Average Annual Heating Customer @ 900 Ccf Per Year				
900	1,565.00	1,597.74	32.74	2.09%

Weighted Revenue Tax Factor:		Delivery		0.02513
		Commodity		0.00513
Gas Supply Charge Factors Effective 2/2/10 (per Ccf):			$	0.80960
New York State Assessment Surcharge:			$	0.03289
Merchant Function Charge (per Ccf):		Present		Proposed
	MFC Admin	$ 0.00924	$	0.00949
	MFC Supply	$ 0.01343	$	0.01373
	Transition Adj.	$ 0.00148	$	0.00148
S.C. No. 1 & 12 Base Delivery Rates		Present - RY 1		Proposed - RY 2
Block 1	First 2 Ccf	$ 19.00	$	21.00
Block 2 per Ccf	Next 48 Ccf	$ 0.8439	$	0.8617
Block 3 per Ccf	Additional	$ 0.3944	$	0.3944

Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Monthly Bill Present - RY 1	Monthly Bill Proposed - RY 2	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 36.93	$ 38.43	$ 1.51	4.08%
10	48.39	49.93	1.53	3.16%
30	77.06	78.65	1.59	2.06%
50	105.73	107.38	1.65	1.56%
100	177.41	179.20	1.80	1.01%
150	234.67	236.45	1.79	0.76%
200	291.93	293.70	1.77	0.61%
250	349.18	350.94	1.76	0.50%
300	406.44	408.19	1.75	0.43%
400	520.96	522.68	1.72	0.33%
500	635.48	637.18	1.70	0.27%
600	750.00	751.67	1.67	0.22%
800	979.04	980.66	1.62	0.17%
1000	1,208.07	1,209.64	1.57	0.13%
1500	1,780.67	1,782.11	1.45	0.08%
2000	2,353.26	2,354.58	1.32	0.06%
3000	3,498.44	3,499.51	1.07	0.03%
5000	5,788.81	5,789.38	0.57	0.01%
7500	8,526.63	8,526.57	(0.06)	0.00%
10000	11,264.45	11,263.76	(0.69)	-0.01%
12000	13,454.71	13,453.52	(1.19)	-0.01%
14000	15,644.96	15,643.27	(1.70)	-0.01%
16000	17,835.22	17,833.02	(2.20)	-0.01%
20000	22,215.73	22,212.53	(3.20)	-0.01%
Average Annual Heating Customer @ 5120 Ccf Per Year				
5120	6,618.00	6,638.59	20.59	0.31%

Weighted Revenue Tax Factor:		Delivery		0.00513
		Commodity		0.00513
Gas Supply Charge Factors Effective 2/2/10 (per Ccf):			$	0.80960
New York State Assessment Surcharge:			$	0.02708
Merchant Function Charge (per Ccf):		Present		Proposed
	MFC Admin	$ 0.00920	$	0.00909
	MFC Supply	$ 0.01923	$	0.01909
	Transition Adj.	$ 0.00380	$	0.00380
S.C. No. 2, 6 & 13 Base Delivery Rates		Present - RY 1		Proposed - RY 2
Block 1	First 2 Ccf	$ 35.00	$	36.50
Block 2 per Ccf	Next 98 Ccf	$ 0.5572	$	0.5604
Block 3 per Ccf	Next 4900 Ccf	$ 0.2704	$	0.2704
Block 4 per Ccf	Additional	$ 0.2206	$	0.2206

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Gas Bills Impacts (Delivery Only)
Rate Year 2 (Twelve Months Ended June 30, 2012)

Service Classification Nos. 1 & 12

Monthly Usage Ccf	Monthly Bill Present - RY 1	Monthly Bill Proposed - RY 2	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 19.61	$ 21.66	$ 2.05	10.47%
4	21.45	23.54	2.09	9.74%
6	23.30	25.43	2.13	9.13%
8	25.15	27.31	2.17	8.61%
10	26.99	29.20	2.20	8.16%
15	31.61	33.91	2.30	7.27%
20	36.23	38.62	2.39	6.60%
25	40.85	43.33	2.49	6.09%
30	45.46	48.04	2.58	5.67%
35	50.08	52.75	2.67	5.34%
40	54.70	57.47	2.77	5.06%
50	63.93	66.89	2.96	4.62%
60	68.56	71.52	2.96	4.32%
80	77.80	80.78	2.97	3.82%
100	87.05	90.04	2.98	3.43%
130	100.92	103.93	3.00	2.97%
170	119.42	122.44	3.02	2.53%
200	133.29	136.33	3.04	2.28%
300	179.53	182.63	3.10	1.73%
1000	503.21	506.70	3.49	0.69%
Average Annual Heating Customer @ 900 Ccf Per Year				
900	832.60	865.34	32.74	3.93%

Weighted Revenue Tax Factor:	Delivery		0.02513
	Commodity		0.00513
New York State Assessment Surcharge:			$ 0.03289

Merchant Function Charge (per Ccf):

	Present	Proposed
MFC Admin	$ 0.00924	$ 0.00949
MFC Supply	$ 0.01343	$ 0.01373
Transition Adj.	$ 0.00148	$ 0.00148

S.C. No. 1 & 12 Base Delivery Rates

		Present - RY 1	Proposed - RY 2
Block 1	First 2 Ccf	$ 19.00	$ 21.00
Block 2 per Ccf	Next 48 Ccf	$ 0.8439	$ 0.8617
Block 3 per Ccf	Additional	$ 0.3944	$ 0.3944

Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Monthly Bill Present - RY 1	Monthly Bill Proposed - RY 2	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 35.30	$ 36.81	$ 1.51	4.27%
10	40.26	41.79	1.53	3.80%
30	52.65	54.24	1.59	3.02%
50	65.04	66.69	1.65	2.54%
100	96.03	97.83	1.80	1.87%
150	112.60	114.38	1.79	1.59%
200	129.17	130.94	1.77	1.37%
250	145.74	147.50	1.76	1.21%
300	162.31	164.06	1.75	1.08%
400	195.45	197.17	1.72	0.88%
500	228.59	230.29	1.70	0.74%
600	261.73	263.41	1.67	0.64%
800	328.02	329.64	1.62	0.49%
1000	394.30	395.87	1.57	0.40%
1500	560.00	561.45	1.45	0.26%
2000	725.71	727.03	1.32	0.18%
3000	1,057.12	1,058.19	1.07	0.10%
5000	1,719.94	1,720.51	0.57	0.03%
7500	2,423.32	2,423.26	(0.06)	0.00%
10000	3,126.71	3,126.02	(0.69)	-0.02%
12000	3,689.41	3,688.22	(1.19)	-0.03%
14000	4,252.12	4,250.42	(1.70)	-0.04%
16000	4,814.83	4,812.63	(2.20)	-0.05%
20000	5,940.24	5,937.04	(3.20)	-0.05%
Average Annual Heating Customer @ 5120 Ccf Per Year				
5120	2,451.48	2,472.07	20.59	0.84%

Weighted Revenue Tax Factor:	Delivery		0.00513
	Commodity		0.00513
New York State Assessment Surcharge:			$ 0.02708

Merchant Function Charge (per Ccf):

	Present	Proposed
MFC Admin	$ 0.00920	$ 0.00909
MFC Supply	$ 0.01923	$ 0.01909
Transition Adj.	$ 0.00380	$ 0.00380

S.C. No. 2, 6 & 13 Base Delivery Rates

		Present - RY 1	Proposed - RY 2
Block 1	First 2 Ccf	$ 35.00	$ 36.50
Block 2 per Ccf	Next 98 Ccf	$ 0.5572	$ 0.5604
Block 3 per Ccf	Next 4900 Ccf	$ 0.2704	$ 0.2704
Block 4 per Ccf	Additional	$ 0.2206	$ 0.2206

Appendix N Sheet 20 of 21

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Gas Bills Impacts
Rate Year 3 (Twelve Months Ended June 30, 2013)

Service Classification Nos. 1 & 12

Monthly Usage Ccf	Monthly Bill Present - RY 2	Monthly Bill Proposed - RY 3	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 23.29	$ 25.34	$ 2.05	8.81%
4	26.80	28.85	2.05	7.65%
6	30.31	32.36	2.05	6.75%
8	33.82	35.87	2.05	6.05%
10	37.33	39.38	2.04	5.47%
15	46.11	48.15	2.04	4.42%
20	54.90	56.93	2.03	3.70%
25	63.68	65.70	2.03	3.18%
30	72.46	74.48	2.02	2.79%
35	81.24	83.25	2.01	2.48%
40	90.02	92.02	2.01	2.23%
50	107.58	109.57	2.00	1.86%
60	120.35	122.34	2.00	1.66%
80	145.88	147.88	2.00	1.37%
100	171.41	173.42	2.01	1.17%
130	209.72	211.73	2.02	0.96%
170	260.79	262.81	2.03	0.78%
200	299.09	301.12	2.04	0.68%
300	426.76	428.82	2.06	0.48%
1000	1,320.48	1,322.73	2.25	0.17%
Average Annual Heating Customer @ 900 Ccf Per Year				
900	1,597.74	1,622.00	24.26	1.52%

Weighted Revenue Tax Factor: Delivery 0.02513; Commodity 0.00513

Gas Supply Charge Factors Effective 2/2/10 (per Ccf): $ 0.80960

New York State Assessment Surcharge: $ 0.03289

Merchant Function Charge (per Ccf):	Present	Proposed
MFC Admin	$ 0.00949	$ 0.00960
MFC Supply	$ 0.01373	$ 0.01388
Transition Adj.	$ 0.00148	$ 0.00148

S.C. No. 1 & 12 Base Delivery Rates		Present - RY 2	Proposed - RY 3
Block 1	First 2 Ccf	$ 21.00	$ 23.00
Block 2 per Ccf	Next 48 Ccf	$ 0.8617	$ 0.8603
Block 3 per Ccf	Additional	$ 0.3944	$ 0.3944

Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Monthly Bill Present - RY 2	Monthly Bill Proposed - RY 3	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 38.43	$ 38.94	$ 0.50	1.30%
10	49.93	50.33	0.41	0.82%
30	78.65	78.83	0.18	0.23%
50	107.38	107.33	(0.05)	-0.05%
100	179.20	178.57	(0.63)	-0.35%
150	236.45	235.79	(0.66)	-0.28%
200	293.70	293.01	(0.69)	-0.23%
250	350.94	350.23	(0.71)	-0.20%
300	408.19	407.45	(0.74)	-0.18%
400	522.68	521.89	(0.79)	-0.15%
500	637.18	636.33	(0.85)	-0.13%
600	751.67	750.77	(0.90)	-0.12%
800	980.66	979.65	(1.01)	-0.10%
1000	1,209.64	1,208.53	(1.11)	-0.09%
1500	1,782.11	1,780.73	(1.38)	-0.08%
2000	2,354.58	2,352.93	(1.65)	-0.07%
3000	3,499.51	3,497.33	(2.18)	-0.06%
5000	5,789.38	5,786.13	(3.24)	-0.06%
7500	8,526.57	8,521.99	(4.58)	-0.05%
10000	11,263.76	11,257.85	(5.91)	-0.05%
12000	13,453.52	13,446.54	(6.97)	-0.05%
14000	15,643.27	15,635.23	(8.04)	-0.05%
16000	17,833.02	17,823.92	(9.10)	-0.05%
20000	22,212.53	22,201.29	(11.24)	-0.05%
Average Annual Heating Customer @ 5060 Ccf Per Year				
5060	6,569.90	6,560.23	(9.67)	-0.15%

Weighted Revenue Tax Factor: Delivery 0.00513; Commodity 0.00513

Gas Supply Charge Factors Effective 2/2/10 (per Ccf): $ 0.80960

New York State Assessment Surcharge: $ 0.02708

Merchant Function Charge (per Ccf):	Present	Proposed
MFC Admin	$ 0.00909	$ 0.00886
MFC Supply	$ 0.01909	$ 0.01879
Transition Adj.	$ 0.00380	$ 0.00380

S.C. No. 2, 6 & 13 Base Delivery Rates		Present - RY 2	Proposed - RY 3
Block 1	First 2 Ccf	$ 36.50	$ 37.00
Block 2 per Ccf	Next 98 Ccf	$ 0.5604	$ 0.5494
Block 3 per Ccf	Next 4900 Ccf	$ 0.2704	$ 0.2704
Block 4 per Ccf	Additional	$ 0.2206	$ 0.2206

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Gas Bills Impacts (Delivery Only)
Rate Year 3 (Twelve Months Ended June 30, 2013)

Service Classification Nos. 1 & 12

Monthly Usage Ccf	Monthly Bill Present - RY 2	Monthly Bill Proposed - RY 3	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 21.66	$ 23.71	$ 2.05	9.47%
4	23.54	25.59	2.05	8.71%
6	25.43	27.47	2.05	8.05%
8	27.31	29.36	2.05	7.49%
10	29.20	31.24	2.04	7.00%
15	33.91	35.95	2.04	6.01%
20	38.62	40.65	2.03	5.26%
25	43.33	45.36	2.03	4.67%
30	48.04	50.06	2.02	4.20%
35	52.75	54.77	2.01	3.82%
40	57.47	59.47	2.01	3.49%
50	66.89	68.88	2.00	2.98%
60	71.52	73.52	2.00	2.79%
80	80.78	82.78	2.00	2.48%
100	90.04	92.05	2.01	2.23%
130	103.93	105.94	2.02	1.94%
170	122.44	124.47	2.03	1.66%
200	136.33	138.37	2.04	1.49%
300	182.63	184.69	2.06	1.13%
1000	506.70	508.95	2.25	0.44%
	Average Annual Heating Customer @ 900 Ccf Per Year			
900	865.34	889.60	24.26	2.80%

Weighted Revenue Tax Factor:		Delivery		0.02513
		Commodity		0.00513
New York State Assessment Surcharge:				$ 0.03289
Merchant Function Charge (per Ccf):			Present	Proposed
	MFC Admin		$ 0.00949	$ 0.00960
	MFC Supply		$ 0.01373	$ 0.01388
	Transition Adj.		$ 0.00148	$ 0.00148
S.C. No. 1 & 12 Base Delivery Rates			Present - RY 2	Proposed - RY 3
Block 1	First 2 Ccf		$ 21.00	$ 23.00
Block 2 per Ccf	Next 48 Ccf		$ 0.8617	$ 0.8603
Block 3 per Ccf	Additional		$ 0.3944	$ 0.3944

Service Classification Nos. 2, 6 & 13

Monthly Usage Ccf	Monthly Bill Present - RY 2	Monthly Bill Proposed - RY 3	Change in Monthly Bill Amount	Change in Monthly Bill Increase
2	$ 36.81	$ 37.31	$ 0.50	1.36%
10	41.79	42.20	0.41	0.98%
30	54.24	54.42	0.18	0.33%
50	66.69	66.64	(0.05)	-0.08%
100	97.83	97.19	(0.63)	-0.65%
150	114.38	113.72	(0.66)	-0.58%
200	130.94	130.26	(0.69)	-0.53%
250	147.50	146.79	(0.71)	-0.48%
300	164.06	163.32	(0.74)	-0.45%
400	197.17	196.38	(0.79)	-0.40%
500	230.29	229.44	(0.85)	-0.37%
600	263.41	262.51	(0.90)	-0.34%
800	329.64	328.63	(1.01)	-0.31%
1000	395.87	394.76	(1.11)	-0.28%
1500	561.45	560.07	(1.38)	-0.25%
2000	727.03	725.38	(1.65)	-0.23%
3000	1,058.19	1,056.01	(2.18)	-0.21%
5000	1,720.51	1,717.26	(3.24)	-0.19%
7500	2,423.26	2,418.68	(4.58)	-0.19%
10000	3,126.02	3,120.11	(5.91)	-0.19%
12000	3,688.22	3,681.25	(6.97)	-0.19%
14000	4,250.42	4,242.38	(8.04)	-0.19%
16000	4,812.63	4,803.52	(9.10)	-0.19%
20000	5,937.04	5,925.80	(11.24)	-0.19%
	Average Annual Heating Customer @ 5060 Ccf Per Year			
5060	2,452.20	2,442.53	(9.67)	-0.39%

Weighted Revenue Tax Factor:		Delivery		0.00513
		Commodity		0.00513
New York State Assessment Surcharge:				$ 0.02708
Merchant Function Charge (per Ccf):			Present	Proposed
	MFC Admin		$ 0.00909	$ 0.00886
	MFC Supply		$ 0.01909	$ 0.01879
	Transition Adj.		$ 0.00380	$ 0.00380
S.C. No. 2, 6 & 13 Base Delivery Rates			Present - RY 2	Proposed - RY 3
Block 1	First 2 Ccf		$ 36.50	$ 37.00
Block 2 per Ccf	Next 98 Ccf		$ 0.5604	$ 0.5494
Block 3 per Ccf	Next 4900 Ccf		$ 0.2704	$ 0.2704
Block 4 per Ccf	Additional		$ 0.2206	$ 0.2206

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric RDM Targets

		Rate Year 1	Rate Year 2	Rate Year 3
S.C. No. 1				
	Customer Months	3,071,952	3,084,720	3,099,150
	kWh	2,059,269,000	2,032,670,000	1,994,580,000
	Revenue	$ 172,021,460	$ 176,753,610	$ 180,729,770
S.C. No. 2 - Non-Demand				
	Customer Months	349,550	350,672	351,949
	kWh	176,048,000	174,847,000	173,449,000
	Revenue	$ 13,220,800	$ 13,701,190	$ 14,177,640
S.C. No. 2 - Secondary				
	Customer Months	148,544	151,848	155,181
	kWh	1,513,733,000	1,506,307,000	1,495,927,000
	kW	4,691,823	4,667,510	4,633,613
	Revenue	$ 55,355,430	$ 57,232,870	$ 59,005,470
S.C. No. 2 - Primary				
	Customer Months	2,068	2,095	2,124
	kWh	253,806,000	252,780,000	252,113,000
	kW	661,397	658,707	657,052
	Revenue	$ 5,077,764	$ 5,240,156	$ 5,405,783
S.C. No. 6				
	Customer Months	18,900	18,900	18,900
	kWh	29,000,000	29,000,000	29,000,000
	Revenue	$ 1,808,110	$ 2,087,070	$ 1,931,650
RDM Revenue Target		**$ 247,483,564**	**$ 255,014,896**	**$ 261,250,313**

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

Appendix O Sheet 2 of 8

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric RDM Targets
Rate Year 1 (Twelve Months Ended June 30, 2011)

	July 2010	August 2010	September 2010	October 2010	November 2010	December 2010	January 2011	February 2011	March 2011	April 2011	May 2011	June 2011	Total
Service Classification No. 1													
Customer Months	252,660	257,413	252,669	256,420	256,566	260,529	253,948	257,658	254,038	258,369	253,669	258,013	3,071,952
MWh	172,689	201,350	192,055	161,778	146,319	168,850	190,719	198,218	177,631	162,126	142,146	145,388	2,059,269
Revenue	$ 14,326,570	$ 15,960,700	$ 15,366,760	$ 13,815,910	$ 12,988,550	$ 14,277,780	$ 15,320,560	$ 15,797,500	$ 14,619,470	$ 13,873,450	$ 12,706,590	$ 12,967,620	$ 172,021,460
Service Classification No. 2													
Nondemand													
Customer Months	27,829	30,306	27,835	30,211	28,036	31,011	27,581	30,337	27,947	30,373	27,748	30,336	349,550
MWh	13,791	15,968	14,306	14,366	12,713	16,462	15,519	17,746	14,942	14,775	12,088	13,372	176,048
Revenue	$ 1,049,970	$ 1,154,390	$ 1,056,110	$ 1,132,800	$ 1,044,130	$ 1,182,640	$ 1,061,990	$ 1,175,930	$ 1,067,090	$ 1,142,740	$ 1,027,690	$ 1,125,320	$ 13,220,800
Primary													
Customer Months	170	174	172	173	178	174	168	175	173	173	163	175	2,068
MWh	22,781	23,435	21,136	21,189	20,459	20,875	20,735	20,075	20,457	20,299	20,689	21,676	253,806
kW	59,954	59,069	59,460	56,196	56,060	54,269	47,500	46,779	47,225	54,386	59,582	60,917	661,397
Revenue	$ 456,228	$ 452,299	$ 451,142	$ 430,415	$ 429,400	$ 417,548	$ 372,441	$ 368,250	$ 371,333	$ 417,363	$ 449,351	$ 461,994	$ 5,077,764
Secondary													
Customer Months	12,297	12,188	12,245	12,281	12,465	12,559	12,215	12,401	12,594	12,372	12,411	12,516	148,544
MWh	140,273	141,334	136,038	121,865	118,909	125,362	126,304	122,806	117,056	117,768	118,504	127,514	1,513,733
kW	421,007	431,804	419,480	405,929	389,466	374,738	350,668	344,113	353,251	380,025	398,963	422,379	4,691,823
Revenue	$ 4,926,920	$ 5,012,330	$ 4,887,830	$ 4,702,420	$ 4,565,850	$ 4,490,070	$ 4,280,830	$ 4,220,900	$ 4,273,740	$ 4,478,080	$ 4,636,030	$ 4,880,430	$ 55,355,430
Service Classification No. 6													
Customer Months	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	18,900
MWh	2,180	2,480	2,180	2,000	1,860	2,570	2,840	3,360	2,750	2,840	1,940	2,000	29,000
Revenue	$ 138,770	$ 154,360	$ 138,770	$ 131,630	$ 123,620	$ 158,640	$ 170,040	$ 196,040	$ 165,770	$ 171,420	$ 127,420	$ 131,630	$ 1,808,110
Total RDM Revenue Target	**$ 20,898,458**	**$ 22,734,079**	**$ 21,900,612**	**$ 20,213,175**	**$ 19,151,550**	**$ 20,526,678**	**$ 21,205,861**	**$ 21,758,620**	**$ 20,497,403**	**$ 20,083,053**	**$ 18,947,081**	**$ 19,566,994**	**$ 247,483,564**

Appendix O Sheet 3 of 8

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric RDM Targets
Rate Year 2 (Twelve Months Ended June 30, 2012)

		July 2011	August 2011	September 2011	October 2011	November 2011	December 2011	January 2012	February 2012	March 2012	April 2012	May 2012	June 2012	Total
Service Classification No. 1														
Customer Months		253,684	258,632	253,682	257,578	257,597	261,658	254,957	258,746	255,045	259,424	254,662	259,055	3,084,720
MWh		170,342	199,583	190,753	160,497	144,419	166,447	187,498	194,925	174,400	159,623	140,317	143,866	2,032,670
Revenue	$	14,706,200	$ 16,381,630	$ 15,799,650	$ 14,264,520	$ 13,403,670	$ 14,672,920	$ 15,653,350	$ 16,134,510	$ 14,953,510	$ 14,258,300	$ 13,119,290	$ 13,406,060	$ 176,753,610
Service Classification No. 2														
Nondemand														
Customer Months		27,916	30,415	27,921	30,316	28,124	31,114	27,666	30,435	28,033	30,469	27,832	30,431	350,672
MWh		13,681	15,844	14,292	14,420	12,688	16,551	15,400	17,555	14,678	14,567	11,945	13,226	174,847
Revenue	$	1,088,290	$ 1,195,270	$ 1,094,650	$ 1,177,400	$ 1,085,260	$ 1,226,190	$ 1,097,240	$ 1,213,370	$ 1,102,420	$ 1,184,070	$ 1,067,830	$ 1,169,200	$ 13,701,190
Primary														
Customer Months		172	176	174	176	180	176	170	177	175	176	165	178	2,095
MWh		22,554	23,298	21,022	21,176	20,396	20,845	20,650	19,923	20,424	20,233	20,652	21,607	252,780
kW		59,350	58,732	59,135	56,177	55,878	54,176	47,301	46,411	47,142	54,206	59,473	60,726	658,707
Revenue	$	467,414	$ 465,582	$ 464,364	$ 445,568	$ 443,618	$ 432,016	$ 385,102	$ 380,018	$ 385,100	$ 431,170	$ 463,672	$ 476,532	$ 5,240,156
Secondary														
Customer Months		12,568	12,465	12,520	12,557	12,740	12,837	12,490	12,678	12,869	12,648	12,685	12,791	151,848
MWh		138,827	140,524	135,428	122,064	118,605	125,112	125,659	121,329	116,777	117,218	118,050	126,714	1,506,307
kW		416,530	429,183	417,478	406,427	388,307	373,843	348,733	339,810	352,253	378,094	397,293	419,559	4,667,510
Revenue	$	5,060,550	$ 5,164,410	$ 5,045,530	$ 4,883,660	$ 4,731,540	$ 4,658,480	$ 4,433,410	$ 4,351,060	$ 4,439,550	$ 4,634,690	$ 4,796,840	$ 5,033,150	$ 57,232,870
Service Classification No. 6														
Customer Months		1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	18,900
MWh		2,180	2,480	2,180	2,000	1,860	2,570	2,840	3,360	2,750	2,840	1,940	2,000	29,000
Revenue	$	143,720	$ 159,680	$ 143,720	$ 136,550	$ 128,300	$ 164,030	$ 214,620	$ 248,360	$ 209,040	$ 216,120	$ 158,860	$ 164,070	$ 2,087,070
Total RDM Revenue Target	**$**	**21,466,174**	**$ 23,366,572**	**$ 22,547,914**	**$ 20,907,698**	**$ 19,792,388**	**$ 21,153,636**	**$ 21,783,722**	**$ 22,327,318**	**$ 21,089,620**	**$ 20,724,350**	**$ 19,606,492**	**$ 20,249,012**	**$ 255,014,896**

Appendix O Sheet 4 of 8

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Electric RDM Targets
Rate Year 3 (Twelve Months Ended June 30, 2013)

	July 2012	August 2012	September 2012	October 2012	November 2012	December 2012	January 2013	February 2013	March 2013	April 2013	May 2013	June 2013	Total
Service Classification No. 1													
Customer Months	254,691	259,688	254,730	258,672	258,722	262,843	256,143	260,000	256,323	260,786	256,044	260,508	3,099,150
MWh	169,030	198,606	189,855	159,311	142,752	164,366	181,315	189,117	169,130	154,682	136,122	140,294	1,994,580
Revenue	$ 15,125,180	$ 16,822,020	$ 16,236,580	$ 14,702,510	$ 13,820,800	$ 15,072,160	$ 15,815,070	$ 16,323,540	$ 15,169,630	$ 14,506,520	$ 13,403,110	$ 13,732,650	$ 180,729,770
Service Classification No. 2													
Nondemand													
Customer Months	28,002	30,512	28,011	30,416	28,219	31,223	27,766	30,550	28,143	30,593	27,950	30,564	351,949
MWh	13,531	15,664	14,182	14,347	12,590	16,468	15,294	17,401	14,511	14,442	11,872	13,147	173,449
Revenue	$ 1,125,130	$ 1,235,790	$ 1,132,400	$ 1,218,380	$ 1,122,680	$ 1,269,330	$ 1,135,780	$ 1,255,790	$ 1,140,570	$ 1,225,560	$ 1,105,530	$ 1,210,700	$ 14,177,640
Primary													
Customer Months	174	178	177	178	183	178	172	180	178	178	168	180	2,124
MWh	22,460	23,233	20,972	21,145	20,334	20,764	20,561	19,826	20,383	20,193	20,650	21,592	252,113
kW	59,094	58,561	58,994	56,091	55,708	53,977	47,108	46,196	47,065	54,109	59,474	60,675	657,052
Revenue	$ 480,620	$ 479,574	$ 478,486	$ 459,931	$ 457,566	$ 445,343	$ 397,533	$ 392,626	$ 398,688	$ 445,269	$ 478,446	$ 491,701	$ 5,405,783
Secondary													
Customer Months	12,845	12,741	12,795	12,834	13,015	13,115	12,767	12,957	13,147	12,929	12,965	13,071	155,181
MWh	137,650	139,548	134,645	121,673	117,974	124,403	124,657	120,038	116,017	116,379	117,263	125,680	1,495,927
kW	412,837	426,043	414,889	404,979	386,082	371,547	345,779	336,017	349,800	375,212	394,472	415,956	4,633,613
Revenue	$ 5,199,290	$ 5,308,230	$ 5,194,930	$ 5,044,580	$ 4,886,130	$ 4,812,750	$ 4,576,350	$ 4,487,690	$ 4,591,990	$ 4,781,710	$ 4,945,580	$ 5,176,240	$ 59,005,470
Service Classification No. 6													
Customer Months	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	1,545	1,605	18,900
MWh	2,180	2,480	2,180	2,000	1,860	2,570	2,840	3,360	2,750	2,840	1,940	2,000	29,000
Revenue	$ 148,560	$ 164,880	$ 148,560	$ 141,360	$ 132,870	$ 169,310	$ 180,910	$ 208,020	$ 176,490	$ 182,530	$ 136,800	$ 141,360	$ 1,931,650
Total RDM Revenue Target	**$ 22,078,780**	**$ 24,010,494**	**$ 23,190,956**	**$ 21,566,761**	**$ 20,420,046**	**$ 21,768,893**	**$ 22,105,643**	**$ 22,667,666**	**$ 21,477,368**	**$ 21,141,589**	**$ 20,069,466**	**$ 20,752,651**	**$ 261,250,313**

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Gas RDM Targets

S.C. Nos 1 & 12

		Rate Year 1	Rate Year 2	Rate Year 3
Sales (Mcf)	Block 1	146,908	142,935	140,777
	Block 2	2,276,471	2,217,721	2,189,764
	Block 3	2,467,729	2,404,791	2,377,519
	Total	4,891,108	4,765,447	4,708,060
Customers		63,950	64,015	64,273
Staff's Customers		64,867	65,368	65,907

S.C. Nos 2, 6 & 13

		Rate Year 1	Rate Year 2	Rate Year 3
Sales (Mcf)	Block 1	20,717	20,962	21,540
	Block 2	690,714	699,569	719,240
	Block 3	3,643,753	3,691,666	3,796,600
	Block 4	1,165,897	1,175,517	1,200,142
	Total	5,521,081	5,587,714	5,737,522
Customers		10,408	10,727	11,142
Staff's Customers		10,493		

Appendix O Sheet 6 of 8

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Rate Year 1 (Twelve Months Ended June 30, 2011) RDM Targets

S.C. Nos 1 & 12

		Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Total
Sales (Mcf)	Block 1	11,246	12,533	11,119	12,740	11,586	13,129	11,741	13,209	11,804	13,150	11,634	13,017	146,908
	Block 2	107,026	92,900	83,387	115,213	180,004	259,866	245,844	278,231	250,331	269,950	217,298	176,421	2,276,471
	Block 3	5,750	7,730	-	7,377	50,116	287,760	434,726	636,311	485,318	382,926	132,783	36,932	2,467,729
	Total	124,022	113,163	94,506	135,330	241,706	560,755	692,311	927,751	747,453	666,026	361,715	226,370	4,891,108
Customers		59,939	67,718	59,819	67,755	59,862	67,782	60,235	67,975	60,680	67,837	59,959	67,841	63,950
Use per Customer	Block 1	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	
	Block 2	1.79	1.37	1.39	1.70	3.01	3.83	4.08	4.09	4.13	3.98	3.62	2.60	
	Block 3	0.10	0.11	0.00	0.11	0.84	4.25	7.22	9.36	8.00	5.64	2.21	0.54	
Total Use Per Customer	Total	2.07	1.67	1.58	2.00	4.04	8.27	11.49	13.65	12.32	9.82	6.03	3.34	
Staff's Customers		60,332	68,161	60,269	68,056	61,006	69,700	61,427	69,335	61,202	69,052	61,030	68,837	64,867

S.C. Nos 2, 6 & 13

		Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Total
Sales (Mcf)	Block 1	1,251	1,325	1,222	1,583	1,762	2,074	1,927	2,098	1,933	2,086	1,756	1,700	20,717
	Block 2	30,706	29,643	29,339	36,574	56,707	79,902	81,141	89,017	81,268	79,204	55,076	42,137	690,714
	Block 3	108,675	104,488	110,426	139,292	264,839	446,752	581,307	611,396	520,540	383,965	233,290	138,783	3,643,753
	Block 4	45,307	33,446	39,013	53,944	77,446	142,189	200,853	212,906	158,820	98,358	63,289	40,326	1,165,897
	Total	185,939	168,902	180,000	231,393	400,754	670,917	865,228	915,417	762,561	563,613	353,411	222,946	5,521,081
Customers		9,724	10,678	9,747	10,908	9,771	10,981	10,097	10,984	10,047	11,027	9,885	11,044	10,408
Use per Customer	Block 1	0.13	0.12	0.13	0.15	0.18	0.19	0.19	0.19	0.19	0.19	0.18	0.15	
	Block 2	3.16	2.78	3.01	3.35	5.80	7.28	8.04	8.10	8.09	7.18	5.57	3.82	
	Block 3	11.18	9.79	11.33	12.77	27.10	40.68	57.57	55.66	51.81	34.82	23.60	12.57	
	Block 4	4.66	3.13	4.00	4.95	7.93	12.95	19.89	19.38	15.81	8.92	6.40	3.65	
Total Use Per Customer	Total	19.12	15.82	18.47	21.21	41.01	61.10	85.69	83.34	75.90	51.11	35.75	20.19	
Staff's Customers		9,781	10,913	9,708	10,982	10,134	11,438	9,713	11,180	10,078	11,095	9,833	11,056	10,493

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Rate Year 2 (Twelve Months Ended June 30, 2012) RDM Targets

S.C. Nos 1 & 12

		Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Total
Sales (Mcf)	Block 1	10,931	12,243	10,851	12,391	11,220	12,744	11,405	12,832	11,489	12,790	11,361	12,678	142,935
	Block 2	104,343	90,887	81,545	112,006	174,341	252,558	239,141	270,927	244,224	263,263	212,294	172,192	2,217,721
	Block 3	5,565	7,567	-	7,174	48,541	279,742	423,056	619,955	473,739	373,660	129,733	36,059	2,404,791
	Total	120,839	110,697	92,396	131,571	234,102	545,044	673,602	903,714	729,452	649,713	353,388	220,929	4,765,447
Customers		60,064	67,777	59,937	67,801	59,968	67,815	60,316	67,990	60,758	67,857	60,028	67,873	64,015
Use per Customer	Block 1	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	
	Block 2	1.74	1.34	1.36	1.65	2.91	3.72	3.96	3.98	4.02	3.88	3.54	2.54	
	Block 3	0.09	0.11	0.00	0.11	0.81	4.13	7.01	9.12	7.80	5.51	2.16	0.53	
Total Use Per Customer	Total	2.01	1.63	1.54	1.94	3.90	8.04	11.17	13.29	12.01	9.57	5.89	3.26	
Staff's Customers		60,899	68,674	60,805	68,553	61,524	70,196	61,929	69,822	61,685	69,526	61,496	69,306	65,368

S.C. Nos 2, 6 & 13

		Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Total
Sales (Mcf)	Block 1	1,261	1,341	1,240	1,584	1,770	2,086	1,940	2,120	1,960	2,120	1,800	1,740	20,962
	Block 2	30,932	29,997	29,768	36,606	56,990	80,346	82,130	90,110	82,610	80,500	56,470	43,110	699,569
	Block 3	109,469	105,758	112,018	139,423	266,207	449,431	588,870	619,280	529,480	390,540	239,220	141,970	3,691,666
	Block 4	45,386	33,462	39,171	53,780	77,510	142,695	202,953	215,144	161,040	99,503	64,210	40,663	1,175,517
	Total	187,048	170,558	182,197	231,393	402,477	674,558	875,893	926,654	775,090	572,663	361,700	227,483	5,587,714
Customers		9,936	10,916	10,001	11,182	10,064	11,293	10,426	11,334	10,413	11,413	10,290	11,455	10,727
Use per Customer	Block 1	0.13	0.12	0.12	0.14	0.18	0.18	0.19	0.19	0.19	0.19	0.17	0.15	
	Block 2	3.11	2.75	2.98	3.27	5.66	7.11	7.88	7.95	7.93	7.05	5.49	3.76	
	Block 3	11.02	9.69	11.20	12.47	26.45	39.80	56.48	54.64	50.85	34.22	23.25	12.39	
	Block 4	4.57	3.07	3.92	4.81	7.70	12.64	19.47	18.98	15.47	8.72	6.24	3.55	
Total Use Per Customer	Total	18.83	15.62	18.22	20.69	39.99	59.73	84.01	81.76	74.43	50.18	35.15	19.86	

Appendix O Sheet 8 of 8

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Rate Year 3 (Twelve Months Ended June 30, 2013) RDM Targets

S.C. Nos 1 & 12

		Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Total
Sales (Mcf)	Block 1	10,684	12,030	10,677	12,157	11,049	12,523	11,249	12,650	11,339	12,616	11,251	12,552	140,777
	Block 2	102,234	89,442	80,353	109,959	171,825	248,780	236,392	267,619	241,449	260,350	210,504	170,857	2,189,764
	Block 3	5,431	7,455	2	7,057	47,843	275,665	418,424	612,803	468,618	369,766	128,666	35,789	2,377,519
	Total	118,349	108,927	91,032	129,173	230,717	536,968	666,065	893,072	721,406	642,732	350,421	219,198	4,708,060
Customers		60,167	67,835	60,091	67,931	60,206	68,028	60,614	68,268	61,134	68,224	60,493	68,288	64,273
Use per Customer	Block 1	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.18	0.19	0.18	
	Block 2	1.70	1.32	1.34	1.62	2.85	3.66	3.90	3.92	3.95	3.82	3.48	2.50	
	Block 3	0.09	0.11	0.00	0.10	0.79	4.05	6.90	8.98	7.67	5.42	2.13	0.52	
Total Use Per Customer	Total	1.97	1.61	1.51	1.90	3.83	7.89	10.99	13.08	11.80	9.42	5.79	3.21	
Staff's Customers		61,358	69,145	61,271	69,043	62,015	70,731	62,453	70,395	62,245	70,150	62,101	69,979	65,907

S.C. Nos 2, 6 & 13

		Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Total
Sales (Mcf)	Block 1	1,310	1,380	1,290	1,630	1,820	2,130	2,000	2,160	2,010	2,170	1,850	1,790	21,540
	Block 2	32,010	31,040	30,880	37,540	58,640	82,350	84,460	92,380	84,910	82,550	58,180	44,300	719,240
	Block 3	113,360	109,530	116,130	143,000	274,000	461,020	606,020	635,670	544,630	400,740	246,710	145,790	3,796,600
	Block 4	46,223	33,802	39,768	54,425	79,002	145,711	208,050	220,224	164,976	101,383	65,527	41,051	1,200,142
	Total	192,903	175,752	188,068	236,595	413,462	691,211	900,530	950,434	796,526	586,843	372,267	232,931	5,737,522
Customers		10,358	11,343	10,427	11,604	10,485	11,712	10,843	11,746	10,824	11,821	10,695	11,849	11,142
Use per Customer	Block 1	0.13	0.12	0.12	0.14	0.17	0.18	0.18	0.18	0.19	0.18	0.17	0.15	
	Block 2	3.09	2.74	2.96	3.24	5.59	7.03	7.79	7.86	7.84	6.98	5.44	3.74	
	Block 3	10.94	9.66	11.14	12.32	26.13	39.36	55.89	54.12	50.32	33.90	23.07	12.30	
	Block 4	4.46	2.98	3.81	4.69	7.53	12.44	19.19	18.75	15.24	8.58	6.13	3.46	
Total Use Per Customer	Total	18.62	15.49	18.04	20.39	39.43	59.02	83.05	80.92	73.59	49.64	34.81	19.66	

Appendix B

ATTACHMENT 4

UPDATED May 14, 2010

Central Hudson Gas & Electric Corporation
Cases 09-E-0588 & 09-G-0589
Net Plant Targets
($000)

Electric[1]	RY1	RY2	RY3	
Electric Net Plant Targets[2]:				
Plant In Service	1,076,792	1,133,187	1,191,241	
Accumulated Reserve	(338,113)	(353,709)	(368,265)	
Net Plant	738,679	779,478	822,976	
NIBCWIP	33,856	35,310	34,525	
Total Net Plant & NIBCWIP	772,535	814,788	857,501	
Less Transmission Sag Mitigation [3]	8,904	14,400	19,905	
Net Electric Plant Targets	763,631	800,388	837,596	5
Depreciation Expense Targets:				
Transportation Depreciation [4]	1,734	1,806	1,879	
Depreciation Expense [4]	27,442	28,916	30,359	
Less Transmission Sag Mitigation	228	348	474	
Electric Depreciation Expense Target	28,948	30,374	31,764	5

Gas[1]	RY1	RY2	RY3	
Gas Net Plant Targets[2]:				
Plant In Service	311,390	324,813	338,473	
Accumulated Reserve	(105,052)	(110,375)	(115,488)	
Net Plant	206,338	214,438	222,985	
NIBCWIP	8,581	8,870	9,505	
Net Gas Plant Targets	214,919	223,308	232,490	5
Depreciation Expense Targets:				
Transportation Depreciation [4]	374	389	405	
Depreciation Expense [4]	7,571	7,883	8,216	
Gas Depreciation Expense Target	7,945	8,272	8,621	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] - Excludes Cost of Removal and Book Cost Retirements.
[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.