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New York Public Service Commission

July 24, 2006, Issued and Effective; July 24, 2006, Issued and Effective

CASE 05-E-0934; CASE 05-G-0935

Reporter
2006 N.Y. PUC LEXIS 227;; 251 P.U.R.4th 20

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service

Disposition: [*1] ORDER ESTABLISHING RATE PLAN

Core Terms

customer, electric, staff, expenditure, fixed price, defer, pulp, energy, retail, appendix, delivery, commodity, deferral, calculate, target, kwh, reliability, ratepayer, rate of return, depreciate, pension, meter, plant, hedge, rate increase, annual, revise, recommend, pre-tax, classification

Panel: COMMISSIONERS PRESENT: William M. Flynn, Chairman; Patricia L. Acampora; Maureen F. Harris; Robert E. Curry, Jr.; Cheryl A. Buley

Opinion

At a session of the Public Service Commission held in the City of Albany on July 19, 2006

BY THE COMMISSION:

INTRODUCTION

This order establishes a three-year rate plan for electric and gas service provided by Central Hudson Gas & Electric Corporation (Central Hudson, the Company). The terms and conditions established by this order are generally consistent with terms and conditions that were set forth in a contested Joint Proposal submitted by Central Hudson, New York State Department of Public Service Staff (Staff), Multiple Intervenors and the United States Department of Defense and all other Federal Executive Agencies (DOD).

PROCEDURAL HISTORY

On July 29, 2005, Central Hudson filed tariff amendments to increase its electric and gas rates each of the next three rate years. For the initial rate year, Central Hudson proposed to increase electric and gas total revenues by approximately $ 52.8 million (13%) and $ 18.1 million (15%), respectively. The filing was suspended and these cases were established to examine the Company's [*2] proposals. [1]

On November 21, 2005, testimony opposing the Company's submission was filed by Staff, the New York State Consumer Protection Board (CPB), and Multiple Intervenors. The Company filed supplemental testimony on November 28, 2005. Rebuttal testimony was filed on December 14, 2005 by Central Hudson, Staff and Multiple Intervenors. Direct testimony was filed by DOD on December 19, 2005. In early January, the Company submitted additional supplemental testimony in response to a Commission Order in Case 04-G-0463. [2]

[*3]

Central Hudson provided its notice of intent to enter into settlement negotiations by letter dated January 6, 2006. In accordance with applicable Commission rules, the notice was reported to the Commission on January 10, 2006. [3]

On January 12, 2006, four parties contacted the presiding officers and proposed a one-month postponement of the evidentiary hearings scheduled to commence on January 18, 2006. The evidentiary hearings were cancelled and a procedural ruling was issued that granted the postponement and established target dates for the submission of a joint proposal. [4]

Public statement hearings were held on March 13 and 14, 2006 in Poughkeepsie, Fishkill, Newburgh and Kingston before Administrative Law Judge Michelle L. Phillips. [*4] In addition, Commissioner Leonard A. Weiss attended the public statement hearing in Poughkeepsie. In total, 33 people made statements on the record. The speakers generally opposed the rate increases sought by Central Hudson.

Several speakers expressed concern that low and fixed income customers could not afford any further increase. Many noted that their bills had already shown significant increases due to the flow-through of commodity costs. Still others stated that schools and businesses would have to pass along any increases through higher taxes and increased prices for goods and services. Some suggested that, if any increase was granted to Central Hudson, it should approximate cost-of-living increases received by the average working person in the Company's service territory. A few opined that the company's level of service did not warrant an increase. Finally, some questioned whether the requested increase was justified, especially given the Company's/CH Energy Group's reported profits of approximately $ 40 million each of the last two years.

Numerous public comments also were received by the Commission through the Department of Public Service Web site and the toll-free telephone [*5] line, and through the U.S. Mail. The concerns expressed therein were similar to those expressed at the public statement hearings. [5] In addition, resolutions opposing the Central Hudson request were received from the Towns of Newburgh, Plattekill, Poughkeepsie and Wappingers Falls.

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[1] Order Suspending Major Rate Filings (issued August 24, 2005); Further Suspension of Major Rate Filings (issued December 14, 2005).

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[2] Case 04-G-0463, Central Hudson Gas & Electric Corporation - Tariff Filing, Order Approving Real-Time Metering Plans, Adopting Daily Balancing Charges and Procedures, and Establishing Further Proceedings (issued November 29, 2005) at 11 (directing Central Hudson to propose and support the permanent rate for daily balancing service in this gas rate case).

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[3] 16 NYCRR 3.9(a) (2).

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[4] See Procedural Ruling on Revised Process and Schedule (issued January 17, 2006).

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[5] One of the comments consisted of a petition, with approximately 25 signatures, opposing the requested rate increase.

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At a conference held on March 9, 2006, the parties agreed to meet with a settlement judge, [6] the Company agreed to further extend the suspension period to the end of August 2006, and evidentiary hearings were rescheduled.

At a procedural conference held on April 3, 2006, several of the parties reported reaching an agreement in principle and proposed a new procedural [*6] schedule that would allow them to finalize a joint proposal. [7]

The Joint Proposal, originally filed with the Commission on April 18, 2006, was subsequently restated on April 19, 2006 and re-filed on April 20, 2006. It recommends a three-year rate plan that is supported by the Company, Staff, Multiple Intervenors and DOD. The Joint Proposal is opposed by CPB, Public Utility Law Project (PULP), Small Customer Marketer Coalition/Retail Energy Supply Association (SCMC/RESA) and Select Energy New York, Inc. (Select Energy) .

At evidentiary hearings held on May 4 and 5, 2006, witness panels representing CPB, the Company and Staff were cross-examined concerning their support of or opposition to the Joint Proposal. In addition, the prefiled testimony and exhibits submitted by the Company, Staff, CPB, Multiple Intervenors and DOD were [*7] moved into evidence. Statements in Support and in Opposition were marked for identification but not placed into evidence. In all, the record consists of 1672 transcript pages and 102 exhibits.

Post-hearing briefs were filed by Staff, Central Hudson, Multiple Intervenors, DOD, CPB, PULP and SCMC/RESA on May 12, 2006. A revised post-hearing brief was submitted by Central Hudson on June 5, 2006. [8]

Public statement hearings on the Joint Proposal were held in Poughkeepsie and Kingston on May 22, 2005. Seven people made statements on the record. Most speakers stated that [*8] the Joint Proposal rates were too high. The balance of the statements, for the most part, reiterated concerns that had been expressed at the March public statement hearings (e.g., customers on fixed and low incomes could not afford any increases; schools budgets would be affected and local governments would have to pass along any increases through higher taxes; and that, if any increase was granted to Central Hudson, it should approximate cost-of-living increases received by the average working person in the service territory). The written, telephonic and electronic comments that were received on the Joint Proposal generally echoed the concerns expressed at the May 22nd public statement hearings.

PROPOSED RATE PLAN AND THE ISSUES BY SECTION [9]

The proposed rate plan consists of a three-year [*9] term beginning on July 1, 2006 and ending June 30, 2009. Its most salient provisions are summarized below.

Electric Revenues, Rates and Bill Impacts

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[6] Administrative Law Judge Jeffrey E. Stockholm was appointed as a settlement judge.

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[7] In light of the parties' report, the evidentiary hearings scheduled to commence on April 10, 2006 were postponed without date. Notice Postponing Evidentiary Hearings (issued April 4, 2006).

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[8] On May 22 and 23, 2006, respectively, CPB moved to strike, in part, and PULP moved to strike in its entirety, the Company's post-hearing brief, claiming that it included statements that violated Commission guidelines and rules. On May 26, 2006, the Company responded, opposing both motions. On June 5, 2006, a ruling was issued granting, in part, the motions to strike. In compliance with the ruling, the Company submitted a revised post-hearing brief.

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[9] In the following discussion, the terms of the Joint Proposal, along with any issues related thereto, are generally summarized and discussed. The term Joint Proposal refers to the Joint Proposal as restated April 19, 2006.

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Electric delivery revenues would increase by about $ 41.4, $ 6.1 and $ 5.5 million, respectively, each rate year. However, by using a portion of electric depreciation reserve, the initial rate year's increase would be moderated, producing three equal increases of approximately $ 17.9 million each rate year.

The revenue allocations among all service classifications, except service classification 9, would be constrained to a minimum increase of 0.75 times the system average and a maximum of 1.25 times the system average. The increase for service classification 9 would be constrained to 0.5 times the system average and would include an additional $ 50,000 allocation of revenue requirement responsibility.

The resulting bill changes for each service classification and each rate year are summarized in Appendix B. The delivery bill increases approximate 10.4%, 9.4% and 8.6%, respectively, each rate year. The delivery bill increases for the residential service class would be about 12.9%, 10.5% and 9.5%, respectively, each rate year. The **[*10]** typical residential electric customer (using 500 kWh per month) would experience a bill impact of about 5.4% in the first rate year.

Electric rates would be further unbundled to more accurately separate and reflect commodity and delivery costs and components. The existing Energy Cost Adjustment Mechanism, which is used to recover electric commodity costs from Central Hudson customers, would be modified to remove New York Independent System Operator Ancillary Services Charges and New York Power Authority Transmission Access Charges. As of July 1, 2007, such costs will be recovered in the Market Price Charges and Hourly Pricing Programs.

Three Market Price Charges would be implemented on July 1, 2006. The first would apply to service classifications 1 (residential) , 2 (general), and 9 (traffic signal); the second would apply to service classification 6 (residential time-of-use); and the third would apply to service classifications 5 (area lighting) and 8 (public street and highway lighting). The proposed Market Price Charges would be based on the average load shapes for each class. As of July 1, 2007, the Market Price Charge for service classification 6 would be further differentiated **[*11]** into on-and off-peak rates. Also, as of July 1, 2007, Central Hudson would cease reimbursing energy service companies (ESCOs) for ancillary service costs and New York Power Authority Transmission Access Charges.

<u>Gas Revenues, Rates and Bill Impacts</u>

Gas delivery revenues would increase by $ 8,003,000 (about 19%) and by $ 6,057,000 (about 11.8%) in the first and second rate years, respectively. There would be no increase in the third rate year. The proposed gas revenue requirements are moderated by deferring and amortizing portions of the gas revenue increases. They also include an interruptible profit imputation of $ 1 million. [10]

[*12]

Gas rates, like the electric rates, would be further unbundled to reflect the transfer of additional commodity-related costs to the proposed Merchant Function Charges.

For residential gas customers, the minimum charge would increase from $ 7.20 to $ 14 a month. As shown in Appendix F, the annual gas rate increase for a typical gas heating customer (1100 Ccf per year) will be $ 92.45 (6.36%).

A new subclass will be established in service class 11, ″Distribution Large Mains″ (″SC 11DLM″), for customers using over 400,000 Mcf/year. The costs allocated to SC 11DLM are set forth in Appendix E and they exclude, among other things, the cost of mains that are less than 6 inches in diameter. The U.S. Military Academy at West Point (USMA) would receive

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[10] Because of the imputation, the Company is permitted each rate year to retain the first $ 1 million in revenues it receives from interruptible service and service to electric generators. However, if the margin does not reach $ 1 million in any rate year, the Company is authorized to surcharge ratepayers for 100% of the first $ 250,000 and 90% of the remaining shortfall. If the margin exceeds $ 1 million in any rate year, the Company must credit ratepayers for 100% of the first $ 250,000 and 90% of the remaining shortfall.

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service in accordance with the provisions of the new SC 11DLM class after the execution of a contract between Central Hudson and the U.S. Department of the Army on behalf of USMA. [11]

[*13]

The existing Gas Supply Charge (GSC), Firm Transportation Rate (FTR), Interruptible Transportation Rate (ITR) and Interruptible Gas Rate (IGR), which are related to the recovery of gas commodity supply costs, would continue, subject to the proposed gas balancing modifications.

Gas Balancing

Effective April 1, 2007, new gas balancing procedures would apply to interruptible and firm transportation customers and to aggregated transport customers. Applicable procedures described in the Company's July 2005 ″Report on Gas Balancing and Cashout Issues″ would be followed in implementing the new gas balancing procedures. Incremental software costs for implementing the procedures would receive deferral accounting. [12]

For the interruptible and firm transportation customers, the volumetric balancing service charge would be implemented as two separate rates: one for daily balanced customers and one for monthly balanced customers. [*14] [13] The charges would be updated at least annually. [14] The updates would be based on each service classification's total consumption and deliveries during the preceding winter period and the Company's then most recently available gas storage and other relevant costs. [15]

Interruptible and firm transportation customers would be allowed to designate an ESCO to make supply nominations and effectuate imbalance exchanges. Commencing April 1, 2007, balancing service charges would be billed to the customers, while imbalance penalties would be billed to the customer's ESCO. [16] ESCOs will be required [*15] to enter into agreements with Central Hudson to pay for such penalties. Prior to April 1, 2007, all charges would continue to be billed to customers.

There also are provisions for the treatment of customers under negotiated contracts, the term of the option period, notification regarding a customer's selected balancing option, the elimination of the current daily balancing provisions, monthly and daily ″cash-out″ procedures, applicable under-delivery index prices, revisions to over-and under-deliveries for monthly balanced customers, purchasing of over-deliveries, and the delivery requirements that would apply after Central Hudson issues an Operational Flow Order. Finally, the Company will pursue withdrawal of its pending rehearing petition concerning gas balancing.

Gas balancing provisions for the aggregated transportation customers include reconciliations and periodic true-ups. Starting

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[11] Additional, non-rate provisions regarding Central Hudson and USMA are set forth in Section XVIII.

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[12] Any such amounts would be subject to carrying charges at the pre-tax authorized rate of return.

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[13] See Appendix K.

[14] SC 11DLM rates would be excepted from the proposed April 1, 2007 update and would remain in effect until March 31, 2008. Effective April 1, 2008, the charges for SC 11 and SC 11DLM would be determined separately, based on the specific peak day history for each class.

[15] The Company would file a statement of Gas Balancing Rates at least 30 days prior to the effective date of an update.

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[16] Balancing Service Charge revenues would be credited to the Gas Supply Charge.

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April 1, 2007, ESCOs can trade offsetting monthly [*16] imbalances as part of the semi-annual reconciliation/true-up.

Rate Unbundling

Existing electric backout credits and related treatment would be maintained through June 30, 2007, except that the cost of the electric backout credits will be charged against the excess electric depreciation reserve. Commencing July 1, 2007, the electric backout credits would be replaced by four Merchant Function Charge groups and by the lost revenue provisions.

The four electric Merchant Function Charge groups will be designated MFC1, MFC2, MFC3 and MFC4. MFC1 applies to service classifications 1 and 6; MFC2 applies to service classifications 2 and 3; MFC3 applies to service classifications 3 and 13; and MFC4 applies to service classifications 5, 8, and 9. The new MFCs include cost-based components to represent commodity-related purchasing, credit and collection, call center costs, advertising and promotions, and related Administrative and General (A&G) expenses and rate base items allocated to each group.

The existing gas backout credits will continue to be recovered through the Gas Supply Charge through June 30, 2007. Gas delivery service MFCs, analogous to those for electric delivery service, [*17] would be implemented on July 1, 2007, with MFC 1 applicable to service classification 1 and MFC 2 applicable to service classification 2.

Each MFC group will be further sub-divided into an MFC[A] and an MFC[B]. MFC[A] includes the allocated portion of credit and collection function costs and 50% of procurement-related call center function costs, plus associated A&G and rate base items. MFC[B] includes commodity purchasing function costs, allocated portions of advertising & promotions function costs and 50% of procurement-related call center function costs, plus associated A&G and rate base items.

Full service customers will be billed for both the MFC[A] and MFC[B]. Retail access customers will be billed by for MFC[A] only. [17]

[*18]

Should total monthly migration of electric or gas customers exceed 30%, short run avoided costs will be established through a collaborative effort among the parties and be submitted for Commission approval. Central Hudson will propose, no later than October 1, 2006, an unbundled bill format for approval by the Commission.

Capital Expenditures

Electric capital expenditures, excluding the Allowance for Funds Used During Construction (AFUDC), would be set at $ 158.078 million ($ 51.944 million for the first rate year, $ 52.530 million for the second rate year, and $ 53.604 million for the third rate year). If actual expenditures fall short of $ 158.078 million by the end of the third rate year, the amount of the shortfall multiplied by 1.5 times the average authorized pre-tax rate of return will be deferred for ratepayer benefit. [18]

Gas plant, excluding both the proposed gas infrastructure [*19] enhancements (described in Section XIV.E of Joint Proposal [19]) and AFUDC, would be set at $ 27.495 million ($ 10.397 million, $ 9.354 million and $ 7.744 million for rate years one, two and three, respectively). If actual expenditures fall short of $ 27.495 million by the end of the third rate year, the amount

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[17] Customers who purchase their commodity service from an ESCO that is not participating in the Company's POR Program would not be billed a MFC by Central Hudson. The discount rate charged to ESCOs that participate in Central Hudson's POR Program would be the same for all service classifications and would consist of an amount reflecting commodity-related uncollectibles costs and a time value of money factor of 0.25%.

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[18] Commencing July 1, 2009, any such amount would be subject to carrying charges calculated at the authorized pre-tax rate of return.

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[19] The Joint Proposal erroneously refers to Section XIII.G. The correct reference is Section XIV.E.

of the shortfall multiplied by 1.5 times the average authorized pre-tax rate of return will be deferred for ratepayer benefit. [20] If actual expenditures for gas infrastructure enhancements exceed $ 15.75 million, the amount above $ 15.75 million may be applied to reduce the gas plant shortfall.

The capital expenditures for common plant would be set, reflecting AFUDC, at $ 21.693 million ($ 7.732 million, $ 7.031 million, and $ 6.930 million for each rate year, respectively). [*20] Again, should actual expenditures fall short of $ 21.693 million by the end of rate year three, the shortfall multiplied by 1.5 times the average authorized pre-tax rate of return will be deferred for ratepayer benefit. [21]

Depreciation

The average service lives, net salvage factors and life tables used to calculate the theoretical depreciation reserve and to establish the depreciation expense reflected in the revenue requirements are set forth in Appendix J and will continue to be used until such levels are changed by the Commission. No adjustments will be made to the depreciation rates used prior to June 30, 2006.

A new depreciation study will be filed by the Company when it files the next major gas, electric or combined rate case. If a combination gas and electric filing is made, the depreciation study would address gas, electric and common plant accounts; if the filing is [*21] limited to only gas or only electric issues, the study need only address the gas or the electric plant accounts.

Deferrals

The Company will continue to use deferral accounting for certain specified items. [22] In addition, the Company will be authorized to defer items specified in and approved by this Order. The deferrals listed in Appendix I will be subject to the Limitation of Deferral provision set forth under the Section X (Earnings Sharing).

Earnings Sharing

The Company's allowed return on equity would be 9.6%. If the Company achieves a regulatory rate of return on common equity above 10.6% in either the electric or gas department, the earnings would be shared as follows: above 10.6% and up to 11.6%, equal (50/50) sharing between the Company and ratepayers; above 11.6% and up to 14.0%, shared 35%/65% between the Company and ratepayers, respectively; and any earnings above 14.0% would be deferred for customers' benefit. [23]

[*22]

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[20] Commencing July 1, 2009, any such amount would be subject to carrying charges calculated at the authorized pre-tax rate of return.

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[21] Commencing July 1, 2009, any such amount would be subject to carrying charges calculated at the authorized pre-tax rate of return.

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[22] See Section IX.

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[23] Ratepayers' portions would be subject to carrying charges at the pre-tax authorized rate of return.

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If the Company achieves a return on common equity above 10.6% in either the electric or gas department, and experiences an under-recovery of migration-related net lost revenues, the net lost revenues will be offset by the Company's portion of the earnings above 10.6%. [24]

Additional Rate Provisions

There would be additional rate-related requirements and conditions, including, but not limited to, the following: accounting procedures for gas mains and services; permitted balance sheet offsets; cessation of the Benefit Fund, but with the preservation and continuation of certain specified uses; deferral conditions and reporting requirements regarding costs for the East Fishkill Substation; a shortfall protection mechanism for electric transmission right-of-way (ROW) maintenance costs; authorization to record gas and electric revenues attributable to the extension **[*23]** of the suspension period to the end of August; establishment of the rate allowances and the deferral and reporting requirements for manufactured gas plant (MGP) site investigation and remediation (SIR) costs; requirements for the deferral and sharing of property tax costs; and the establishment of factors for common costs allocation, electric losses and lost and unaccounted for gas. They are set forth in Section XI.

Low-Income Program

A new low-income program, instituted in two phases, will replace Central Hudson's current low-income program ("Powerful Opportunities" or "POP"). An interim program will replace the POP Program and continue until the second phase ("Enhanced Powerful Opportunities" or "EPOP") is operational. In both phases, the low-income program will be directly administered and managed by the Company. Program funding will be $ 1.148 million, $ 1.32 million, $ 1.50 million, for each of the three rate years, respectively. Unless adjusted by Commission order, the funding will continue at $ 1.5 million per rate year thereafter. Differences between the funding level and actual expenditures during a rate year will be deferred. [25] If such differences are due to over-expenditures, **[*24]** the deferral will be limited to no more than 15% of the rate year funding level. If such differences are due to under-expenditures, the remaining balance will be used in subsequent rate years for low-income program expenditures.

Design, implementation and other program issues for the Enhanced Powerful Opportunities Program will be established through a collaborative effort among the Company and other interested parties. This effort will begin not later than 10 days after Commission action on the Joint Proposal. Working with this collaborative, the Company will complete its development of a detailed EPOP program proposal within 45 days of the Commission's action on this Joint Proposal. The resulting proposal will be submitted for Commission approval and, once approved, would be completely implemented no later than September 1, 2007.

The interim program will replace the existing low-income program as soon **[*25]** as reasonably feasible, so that there is no lapse in the availability of a low-income program.

Customer Service Quality Performance Mechanism

The current Customer Service Quality Performance mechanism will remain in effect through December 31, 2006. A new Customer Service Quality Performance mechanism will become effective on January 1, 2007. A maximum, potential adjustment of 25 basis points, to be calculated on a combined electric and gas basis, will be incurred if the specified service quality targets are not met.

Gas Safety

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[24] Any remaining net lost revenues would be deferred for future recovery subject to carrying charges calculated at the authorized pre-tax rate of return.

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[25] The deferred amounts would be subject to carrying charges calculated at the authorized pre-tax rate of return.

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Gas Safety targets and rate adjustment levels will continue at their present levels. The targets will be changed for and after calendar year 2008 and will remain at those levels until changed by the Commission. All gas safety target metrics will be calculated on a calendar year basis. The targets and rate adjustments apply to leak management, prevention of excavation damages, and emergency response.

Additional targets will be established for expenditures that enhance the gas infrastructure, namely, the replacement of gas cast iron and steel pipe. The target for such expenditures will be set at $ 15.75 million over the three rate years, but not less [*26] than $ 4.5 million in each calendar year. If actual expenditures fall short of the target level by the end of 2009, Central Hudson would defer, for ratepayer benefit, the amount of the shortfall multiplied by 1.5 times the average authorized pre-tax rate of return. [26] This deferral would be the sole remedy against the Company for failure to fully expend the forecast level for replacement of certain cast iron and steel mains and services. [27] There are also reporting and record keeping requirements related to the gas safety mechanisms and targets.

Electric Reliability

Effective January 1, 2006, the target for the Customer Average Interruption Duration Index (CAIDI) will be 2.50, and the target for the System Average Interruption Frequency Index (SAIFI) will be 1.45 for each calendar year. A rate adjustment of 10 basis points (electric) will [*27] be assessed against Central Hudson for each failure to satisfy an annual target threshold. Certain events, such as ″major storm″ outages or catastrophic events, would be excluded from the indices' calculation.

In addition to the SAIFI and CAIDI targets, reliability-oriented targets for significant construction projects would be established. They include rate adjustments for failure to: complete 100 circuit miles of enhanced distribution line clearing during each respective rate year (5 basis points per rate year); complete and energize the proposed East Kingston substation by June 30, 2007 (5 basis points, electric) ; and complete reliability-related construction projects in calendar years 2007 and 2008, respectively [28] (5 basis points per calendar year).

The Company will pursue withdrawal of its rehearing petition concerning electric reliability. The Joint Proposal [*28] also recommends a 37.5 basis point penalty for not meeting reliability target thresholds in 2002 and 2004 and would allow the Company to reverse the 2005 reliability penalty.

The proposed rates support a workforce of 855 employees and allow Central Hudson to hire additional line mechanics. Staff and the Company will meet quarterly to discuss reliability, and employee levels and utilization, and the Company will file compliance reports concerning the electric reliability targets. The reliability performance mechanism will remain in place until the Commission adopts a subsequent approach.

Meter Reading and Billing Studies

A study of the costs and benefits of converting from bi-monthly meter reading and billing to monthly meter reading and billing would be developed by the Company and filed for Commission approval. It will identify the costs associated with the conversion to monthly metering and billing and the net revenue requirements effects, and include an implementation plan.

An Automated Meter Reading (AMR) Pilot would be developed by the Company and filed for Commission approval. It

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[26] Commencing on January 1, 2010 such deferral will be subject to carrying charges calculated at the authorized pre-tax rate of return.

[27] See Section XIV.E(1).

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[28] Such projects will be identified by Staff from among the electric reliability-related projects identified in the Company's updated capital forecasts.

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will include 5000 meters and be funded from unused amounts that were set aside for such purposes. [*29] Total costs will be capped at $ 1.5 million.

Retail Access

The existing Market Match, Market Expo, ESCO Ombudsman, and ESCO Referral programs would continue, as would the Competition Awareness and Understanding Survey. In addition, one or two annual Energy Fairs would be conducted by Central Hudson, in collaboration with Staff and ESCOs, prior to the winter heating season. Finally, a Competition Education Campaign, aimed at promoting customer migration, would be funded at $ 350,000 per rate year. [29]

PARTY COMMENTS ON JOINT PROPOSAL

Statements in Support [30]

[*30]

Central Hudson

Central Hudson states that the Joint Proposal is a comprehensive three-year rate plan that implements the Commission's policy objectives, provides much needed rate relief, and proposes a rational outcome for these proceedings. Central Hudson argues that the Joint Proposal should be adopted as presented because it satisfies the Commission's criteria for proposed settlements. [31]

With respect to the requirement for consistency with law and policy, Central Hudson asserts that the Joint Proposal provides just and reasonable rates that are based on extensively investigated costs and found to be justified by the proponents. Central Hudson notes that the settlement negotiations commenced after parties had engaged in extensive discovery and filed their evidentiary cases, and that discovery continued through negotiations. The Company contends that, as a result, parties were fully aware of the revenues and costs used to develop the proposed rates. [32]

[*31]

The Company states that its cost elements increased in virtually every area of its operations since the last time rates were increased. The Company notes there have been significant negative rate allowances for pension and other post-retirement benefit (OPEB) costs, which are no longer appropriate, and therefore have been updated, consistent with applicable Commission policy. [33]

The Company observes that rate increases were moderated using the book depreciation reserve in excess of the theoretical reserve, while still preserving the previously established rate base. The Company continues that gas rate moderation was

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29 Actual expenditure shortfalls below the $ 350,000 rate allowance will be deferred for expenditure on the same purposes in future rate years.

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30 Statements in Support were marked for identification as Exhibits ("Ex.") 63 (Multiple Intervenors), 65 (Central Hudson), and 66 (Staff) and are summarized below.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

31 Ex. 65 at 2.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

32 Ex. 65 at 3-4.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

33 Ex. 65 at 4.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

achieved by reducing the size of the first year rate increase and deferring the amortization of those assets to the beginning of the second rate year. [34] The Company reports that electric and gas delivery rates are fully unbundled, consistent with Commission policies. [35]

[*32]

Central Hudson argues that the Joint Proposal compares favorably with the probable outcome of litigation and strikes a reasonable balance among the parties' competing evidentiary positions. [36]

The Company asserts that the Joint Proposal favors consumers. It states that the allowed 9.6% rate of return on common equity is at the lower end of a zone of reasonableness, and is offset to a degree by the earnings sharing provisions. Central Hudson argues that its ability to attain any return above 9.6% requires it to achieve efficiencies in its operations. It adds that the opportunity for a return above 10.6% is restricted by the earnings sharing provisions and by a limitation on future deferrals. According to the Company, these provisions, coupled with the proposed rates and other provisions, favor consumers' interests. [37]

[*33]

The Company adds that the Joint Proposal precludes it from improving earnings by deferring capital expenditures or electric transmission ROW vegetation management programs because under-expenditures are subject to requirements that the Company defer, for ratepayer benefit, 150% of the revenue requirement equivalent of any shortfall over the three-year term. [38]

According to Central Hudson, the rate increases should be viewed in the context of recent rate decisions that have created a pent-up need for increased rates and the amount of inflation since Central Hudson's delivery rates were last increased. Central Hudson states that its delivery rates have not increased in more than 12 years for electric service, and 15 years for natural gas, and that its low electric rates, since 1993, have "saved customers hundreds of millions of dollars compared to the state average." [39]

[*34]

In support of the proposed rate increases, Central Hudson states that, over the last ten years, customers' use of electricity and natural gas has risen by 20% and 27%, respectively; the percent of residential customers with air conditioning increased from 52% in 1993 to more than 85% by 2005; average household electricity use increased by 15 percent from 1993 to today; and since 1993, the consumer price index has risen by 39 percent, raising the costs associated with providing service. Meanwhile, Central Hudson contends that its employee levels (net of the former power plants) declined by nearly 25 percent since 1993, while the number of electric and gas customers increased by 11% (30,000) and 17% (9,900),

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[34] Ex. 65 at 4-5.

[35] Ex. 65 at 5.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[36] Ex. 65 at 6-7.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[37] Ex. 65 at 7-8.

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[38] Ex. 65 at 8.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[39] Ex. 65 at 8-9.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

respectively. The Company claims that this represents an average productivity trend of 4% per year and a customer to employee ratio of 425 to one, placing Central Hudson in the top quartile among utilities nation-wide. [40]

Central Hudson also highlights its customer service, pointing to its tree **[*35]** trimming programs' 33% reduction in the number of customers experiencing storm outages between 2002 and 2004; its infrastructure improvements that avoided outages to more than 28,000 customers per year; and its positive customer surveys in which overall customer satisfaction rose from 90.2 percent to 95.1 percent from 1998 to 2004. [41]

The Company also asserts that the Joint Proposal has support from generally adverse parties, including Staff, Multiple Intervenors, and DOD. In addition, it reports that the proposed Low-Income Program reflects CPB and PULP's active participation. Finally, Central Hudson argues these proceedings provided an adequate record basis for the Commission to render a rationally based decision. [42]

Staff

Staff asserts that the Joint Proposal should be adopted because it satisfies the established **[*36]** criteria for judging the reasonableness of settlements. Staff notes that a diverse group of parties support the Joint Proposal, including Multiple Intervenors and DOD. [43]

Staff states that the rate increases are necessary to meet escalating pension and OPEB costs and other inevitable cost increases. To mitigate the increases, it notes that various rate design and rate phase-in mechanisms were devised to alleviate the rate shock that would otherwise occur. Staff continues that the three-year plan provides certainty on the magnitude and timing of the increases, so consumers can effectively plan their energy usage and so the Company can provide safe and adequate service. According to Staff, the time between rate filings permits Central Hudson to reduce costs and increase efficiencies, which will benefit ratepayers who share in the resulting higher earnings. [44]

[*37]

Staff contends the record adequately justifies adoption of the Joint Proposal's terms. It states that financial terms are derived from Central Hudson's original testimony and from discovery. Staff asserts that parties had ample opportunity to review the Company's support and to conduct extensive discovery. Staff contends that the Joint Proposal's appendices demonstrate a detailed agreement as to the costs and revenues underlying the proposed base rates. [45]

Staff observes that the proposed, successive electric rate increases are moderated and phased-in. Staff contends that the income statements demonstrate that the increase in revenue requirement is constrained, in part, by providing for a

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[40] Ex. 65 at 9-10.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[41] Ex. 65 at 10.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[42] Ex. 65 at 11.

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[43] Ex. 66 at 8.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[44] Ex. 66 at 8-9.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[45] Ex. 66 at 9-10.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

reasonable, but modest, ROE. [46] Staff states that gas rates will increase but the rate plan provides for moderation and for no increase in the third rate year, both of which benefit customers. [47]

[*38]

Staff states that the rate increases are admittedly sizable, but inevitable - mainly due to pension and OPEB obligations, which cannot be escaped, and to preserving safe and reliable service, which requires expenditures. Staff notes that a downturn in financial markets required the Company to make substantial contributions to pension and OPEB plans, a trend that is expected to continue. Staff states that rates must be adjusted to recognize not only this fact, but the corresponding fact that earnings from pension and OPEB plans are no longer available as a rate offset. Staff points to its appendices to demonstrate that these expenses account for 55% of the electric increase and 47% of the gas increase, plus another 32% of the gas rate increase for recovery of prior pension and OPEB expense deferrals. Staff continues that reliability expenditures and other mandated costs amount to another 20% of the electric increase and 8% of the gas increase. According to Staff, the overall impact of such expenditures, 75% of the electric increase and 87% of the gas increase, constitute the bulk of the rate increase. [48]

[*39]

Staff asserts that the bill impacts were constrained so that a typical residential electric customer using 500 kWh per month will see a 5.4% bill impact in rate year one, 5.0% in rate year two, and 4.6% in rate year three, while a typical residential annual heating gas customer will see bill impacts of 6.36% in the first rate year and 5.17% in the second rate year. Staff argues that the proposed bill impacts are acceptable because the underlying rates have been structured to satisfy obligations for pension/ OPEBs and safety and reliability, and to avoid hidden costs that would force rate increases at the end of the three-year plan. [49]

Staff contends that the proposed electric rate design accords with Commission policy on hedging electric commodity costs by precluding new hedges for Central Hudson's larger commercial and industrial customers who experience real-time commodity prices and by recovering residential customers' hedging through the commodity rate. [50]

[*40]

Staff notes that the Joint Proposal does not provide for a fixed price option for gas or electric service, but asserts that requiring a utility-provided fixed price option runs counter to Commission Policy and, thus, is no reason to withhold approval. Citing to a July 2005 Order, [51] Staff observes its statement that a then-existing Central Hudson fixed price option for gas service distorts the market, acts as a barrier against ESCO entry and is an obstacle to innovation. [52]

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[46] Ex. 66 at 12.

[47] Ex. 66 at 13-14.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[48] Ex. 66 at 14-16.

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[49] Ex. 66 at 16-17.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[50] Ex. 66 at 17-18.

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[51] Case 05-G-0311, Small Customer Marketer Coalition, Order Directing the Future Termination, Subject to Conditions, of a Fixed-Price Offer (issued July 22, 2005)(July 2005 Order).

[52] Ex. 66 at 19.

Staff notes that the new gas balancing program rectifies the current situation under which Central Hudson was the only large local gas delivery company in New York without daily balancing procedures for its largest customer. [53] Staff asserts that providing daily and monthly gas balancing for larger customers and resolving other outstanding **[*41]** gas balancing issues is consistent with Commission orders. [54]

Specifically, Staff argues that with the implementation of the proposed balancing and cashout provisions, obsolete provisions in Central Hudson's tariff will be eliminated and imbalances will be properly priced, thus sending the correct price signals and encouraging accurate arrangements for commodity delivery. Staff also asserts that the proposed changes will enhance reliability and minimize deviations between proposed use and actual deliveries. Staff claims that daily and monthly balancing rates have been revised to avoid cross-subsidizations that might exist under the present system. Finally, Staff contends that added opportunity to trade imbalances will allow customers to avoid potential imbalance penalties during times when Central Hudson's overall system is largely balanced. [55]

[*42]

Staff asserts that the Joint Proposal's resolution of the complex and contentious dispute between Central Hudson and USMA over rates for gas delivery service to West Point is one of its major benefits. Staff notes that in addition to arriving at cost-based rates for service to USMA, expensive and time-consuming litigation in front of the Armed Services Contract Board of Appeals, and over possible appeals from its initial decision, is averted. [56]

Staff observes that the Joint Proposal provides for further rate unbundling that conforms with Commission policies. Specifically, Staff notes that existing backout credits are replaced with MFCs that are cost-based and are set at tiered levels to recognize the cost differentials for supplying commodity to ESCO customers within and without Central Hudson's Purchase of Receivables (POR) program. Staff asserts that establishing and coordinating MFCs and POR program expenses and charges this way complies with the recent policy developments and would have **[*43]** been difficult to achieve in a litigated proceeding. [57]

Staff states the Joint Proposal resolves a highly contentious dispute regarding the proper calculation of electric and gas depreciation, and the size of excess electric depreciation reserve. In addition, Staff notes that the contents and analyses required of a depreciation study to be filed in subsequent proceedings are established, thus eliminating potential, future dispute. [58]

Staff argues that the provision to offset certain deferrals against Central Hudson's share of any over-earnings is ″of particular importance″ because it protects ratepayers by establishing a sharing mechanism that kicks in if Central Hudson accumulates significant deferrals in its favor and also over-earns. Staff argues that the recommended earnings sharing also

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[53] Ex. 66 at 20.

[54] Ex. 66 at 20-21.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[55] Ex. 66 at 21-22.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[56] Ex. 66 at 22-23.

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[57] Ex. 66 at 23-24.

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[58] Ex. 66 at 25-26.

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conforms with [*44] numerous other similar rate plan provisions the Commission has adopted and that its allocation of benefits and risks is appropriate. [59]

Staff asserts that the allowed 9.6% return is reasonable, noting that it reflects several relevant updates, and is below that adopted in other recent rate plans. [60]

Staff notes that the rates provide funds to build a substation, expand electric transmission ROW maintenance efforts, and replace gas cast iron and bare steel pipe. Staff observes that such costs can no longer be offset, as in the past, by the Benefit Fund, which has been depleted, and are required, in part, by new Commission guidelines on ROW maintenance. Staff observes that any shortfalls in these expenditure levels are deferred for ratepayer benefit, thus encouraging Central Hudson to make the expenditures necessary [*45] to preserve electric system reliability and gas system safety. [61]

With respect to low-income programs, Staff notes that the Joint Proposal provides for rapid implementation of an interim program that will rectify the most serious deficiencies in Central Hudson's existing program and for an enhanced program that is based on elements which represent the Commission's most recent thinking on appropriate low-income program policies. According to Staff, the enhanced program will carefully target assistance to the customers most able to benefit from that assistance, and tailor the amount of the assistance to meet the particular needs of a participating household. Staff notes that program funding will be increased from $ 1.148 million in Rate Year 1, to $ 1.32 million in Rate Year 2, and $ 1.50 million in Rate Year 3, and that any unspent amounts will be deferred for low-income program use in subsequent years. [62]

[*46]

Staff notes that the electric reliability mechanism has been the source of considerable controversy. Staff states that the previous rate order, in recognition of plans to install a new Outage Management System (OMS), allowed Central Hudson to request appropriate adjustment of electric reliability indices if it could show the introduction of OMS affected the calculation of the reliability indices. Staff also notes that, following implementation of OMS, Central Hudson had difficulty in meeting the SAIFI and CAIDI reliability indices, which ultimately resulted in contested reliability adjustments. Staff states that the Joint Proposal reasonably resolves these issues by providing that the 2001 Commission rate decision will remain in effect and by requiring the preservation of the 2002 and 2004 adjustments but excusing the 2005 adjustment. [63]

Staff observes that the Joint Proposal provides for several studies on improving billing and metering that might benefit Central Hudson's customers, including [*47] an AMR Pilot Program. Staff says the pilot will allow Central Hudson to gain experience with AMR technology and learn more about the cost and benefits of installing this type of metering, but will not impact bills as the program would be funded from unused competitive metering funds and excess electric depreciation reserve. [64]

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[59] Ex. 66 at 27.

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[60] Ex. 66 at 28.

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[61] Ex. 66 at 29-33.

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[62] Ex. 66 at 34-35.

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[63] Ex. 66 at 37-40.

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[64] Ex. 66 at 40-41.

Staff asserts that the Joint Proposal's Retail Access provisions advance the Commission's policies for creating competitive opportunities in retail energy markets, while giving Central Hudson clear direction on the best practices for furthering such policies. [65]

Multiple Intervenors

Multiple Intervenors state that the proposed rate increases apparently cannot be avoided in this proceeding. First, they note that Central Hudson's annual expense related to pensions and OPEBs has increased [*48] substantially over the amounts contained in the current electric and gas rate plan. Second, Multiple Intervenors note the need for Central Hudson to undertake certain investments in its electric and gas systems in order to maintain and improve reliability. Finally, they observe that a material portion of the rate increases relate to programs mandated by the Commission. [66]

One of the primary reasons cited by Multiple Intervenors for their support of the Joint Proposal is the considerable effort that was made to moderate the rate increases to the maximum extent practicable. They argue that the negotiated electric and gas rate moderation is beneficial to customers and in the public interest. [67]

Another factor highlighted by Multiple Intervenors is that the Joint Proposal has been drafted in a manner that should allow [*49] it to continue after the proposed three-year term without requiring immediate, material rate increases.

Multiple Intervenors also cite to the resolution of electric revenue and service classifications 3 and 13 rate design issues as a critical component, stating that the allocations are consistent with the best available cost of service evidence. They conclude that the provisions should be adopted, along with the constraints proposed by the settling parties.

Multiple Intervenors argue that the constraints on the revenue allocation are appropriate in this instance because the rate increases are substantial and, if unconstrained, would result in unacceptable customer impacts. They add that the cost of service evidence does not indicate the need for major shifts in revenue responsibility. [68]

Multiple Intervenors support the proposed rate design for service classifications 3 and 13, stating that it reflects: (i) cost-based monthly customer charges; (ii) recovery of the residual revenue requirement through [*50] per kW demand charges; and (iii) the elimination of per kWh energy charges. They argue that, in this circumstance, energy charges are inappropriate because almost all of Central Hudson's delivery-related costs are fixed in nature and should not vary based on energy consumption. [69]

Multiple Intervenors also note their express support for the resolution of gas transportation balancing issues. They argue that the Commission should accord substantial weight to the fact that numerous parties with diverse interests were able to resolve a number of very complicated gas balancing issues, including, but not limited to: (i) the appropriate monthly

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[65] Ex. 66 at 41.

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[66] Ex. 63 at 2-3.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[67] Ex. 63 at 3.

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[68] Ex. 63 at 4.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[69] Ex. 63 at 5.

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balancing thresholds and rates for large transportation customers; (ii) the appropriate daily balancing thresholds and rates for large transportation customers; (iii) the transition period for the implementation of daily balancing service; (iv) the rules governing the cash-outs of imbalances; and (v) the rules regarding how imbalances, and imbalance penalties, are [*51] calculated. They assert that the proposed revenue allocation is reasonable and consistent with the cost of service evidence.

Multiple Intervenors urge consideration of the fact that the Joint Proposal is an integrated agreement and the moderation of the electric and gas rate increases, electric revenue allocation, service classification 3 and 13 electric rate design, gas balancing provisions affecting large transportation customers, and gas revenue allocation are critically important and inextricably linked to their decision to execute and support the proposal. [70]

Statements in Opposition [71]

[*52]

CPB

CPB opposes the Joint Proposal, claiming it does not satisfy the Commission's settlement guidelines and requires improvement to properly benefit customers. First, CPB recommends that the residential and small commercial customers be allowed to purchase electric and gas commodity service from the Company at a fixed price. [72] Though recognizing that the July 2005 Order directed Central Hudson to terminate its gas fixed price option, CPB argues that the order is not binding because the basis upon which the Commission acted, namely that retail competition would be inhibited if utilities offered fixed price options, is not supported by the current retail market in Central Hudson's service territory. CPB claims that ESCOs generally have not met consumers' interest in fixed price offerings, despite the absence of utility-provided fixed price options. [73] CPB also claims that Commission policy offers the flexibility to pursue utility-provided fixed price options where, as here, the retail market has not met customers' needs. CPB contends there is a compelling need to provide utility fixed price options to consumers so that they have an additional tool to manage their energy bills. [*53] [74]

CPB expresses concern that the Joint Proposal devotes inadequate resources to outreach and education on high energy prices. CPB notes that $ 350,000 will be spent annually on a Competition Education Campaign, but the Joint Proposal is silent on the outreach and education to be conducted for purposes other than retail competition. CPB recommends that customers be provided information on the cause of high energy prices, actions they can take to manage their energy bills, and how to obtain bill payment assistance, and that $ 175,000 of the amount earmarked for the Competition Education Campaign be redirected therefor. [75]

CPB recognizes that the electricity and gas delivery rate increases are necessary and appropriate, but it asserts that the Joint Proposal overstates revenue [*54] requirements and does not balance the Company's and customers' interests. CPB

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[70] Ex. 63 at 5-6

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[71] Statements in Opposition were marked as Exhibits 61 (SCMC/RESA), 62 (Select Energy) , and 64 (PULP) and are summarized below. CPB submitted its opposition as direct testimony (Tr. 698-775), however, in response to Central Hudson's motion to strike (Tr. 792-795), CPB agreed to redact and submit portions of its opposition as Exhibit 102 (Tr. 1614-1617).

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[72] Tr. 713.

[73] Tr. 718-720.

[74] Tr. 720-721.

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[75] Tr. 721-723.

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recommends modifications to the construction expenditures, ROW maintenance expenditures, the discount rate used in pension and OPEB expense projections, the automated meter reading program, outreach and education expenses, the structure of the Company's pension plan, retail access expenditures, the treatment of certain customer money set aside for metering purposes, and the excess depreciation reserve surplus. CPB contends that its modifications would not affect the Company's earnings but would benefit customers. CPB also recommends modifications that would affect the Company's earnings, including reductions to storm expense, MGP remediation expense and the allowed return on equity. [76]

With respect to capital expenditures, CPB claims they would increase by 27.6% in the 18-month period between 2005 and the 2006 rate year and far exceed any party's recommendations. CPB recommends that capital expenditures be projected at [*55] the average of the expenditures made in the last four years adjusted for twice the overall inflation level since 2005. [77]

Concerning ROW maintenance expenses, CPB claims there is substantial uncertainty regarding the level of such expenditures and ratepayers are not protected if actual spending is less than projected. CPB also claims that cost savings or other benefits expected to result from such expenditures are not reflected and it doubts that a 107% increase in annual spending is needed at this time.

CPB also notes that, unlike transmission ROW expenditures, there is no shortfall protection for distribution ROW maintenance expenditures. CPB asserts that shortfall protection is needed for expenses that account for 78.4% of total ROW maintenance expenditures. CPB recommends that the ROW maintenance expenditures be revised downward by $ 3 million each rate year, to reflect recent historical spending levels, and that the Company provide ratepayer protection if actual distribution ROW maintenance expenditures [*56] fall short of the rate allowances. If the Company makes ROW maintenance expenditures beyond the amount that CPB advocates, it recommends deferral accounting for such amounts, with any requests to recover such deferrals accompanied by a comprehensive report explaining the need for the expenditures. [78]

CPB also takes issue with the projected storm expense. While recognizing that the projections were derived from a four-year average of historical expenditures (adjusted for inflation), CPB claims that, given the substantial increases in ROW maintenance expenditures, all else being equal, storm expense should continue to decline. It therefore recommends that projected storm expense be reduced $ 2 million, to reflect the average of such expenditures beginning in 2004. [79]

With respect to MGP remediation costs, CPB asserts [*57] that the Company should be responsible for a portion of the associated program expenses. CPB states that where, as here, the utility is embarking on a program involving many projects and significant cost, there is a compelling need to constrain rates and to encourage cost minimization. CPB therefore recommends that the Company absorb 10% of such costs, and cites to previous PSC orders as support for both cost sharing and deferral limitations. [80]

CPB notes that the proposed rates use a 5.5% discount rate for pension and OPEB obligations. It asserts that a 5.5% discount rate likely overstates pension/ OPEB expense and therefore should be increased to 5.75% for this Company. CPB

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[76] Tr. 723-724.

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[77] Tr. 725-730.

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[78] Tr. 730-737.

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[79] Tr. 737-738.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

[80] Tr. 738-742

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asserts this recommendation is fair to the Company and reduces the revenue requirement by more than $ 1 million per year. [81]

CPB also takes [*58] issue with the allowed cost of equity. Specifically, it disagrees with the removal of the CH Energy Group from the proxy group and with changing the weighting between the traditional and zero-beta CAPM methods from 75/25 to 50/50. Finally, CPB disagrees with a 38 basis point stay-out premium. CPB states that the methods developed in the Generic Finance Proceeding indicate that the return should be reduced. [82]

CPB acknowledges that pension and OPEB expense is one of the main drivers of the rate increases. It notes that Central Hudson continues to offer a defined benefit pension plan to its management and executive employees, subject to certain eligibility requirements. CPB asserts that defined benefit pension plans are more expensive and that many employers have replaced them or have begun to transition away from them. CPB is concerned that if the Company follows other large employers and transitions away from a defined benefit pension plan, it will retain all associated savings. CPB therefore recommends [*59] that the Joint Proposal be modified to provide ratepayers two-thirds of any savings from transitioning away from the current defined pension plan. CPB asserts that this approach is fair to the Company because it provides a financial incentive to pursue cost reductions and also is fair to the ratepayers who would share in the cost savings. [83]

CPB notes that funds reserved for metering initiatives will be kept and preserved for that purpose. CPB instead recommends the amount (approximately $ 466,000) be used to mitigate bills. CPB notes that it has been two and one-half years since the Commission originally established the funds, and no reasonable metering proposal has been advanced in that time. It therefore asserts that the funds are better used to mitigate increases. [84]

CPB also opposes the AMR Pilot Program, stating [*60] that no party proposed such a program in their initial testimony. CPB contends that the magnitude of the proposed delivery rate increases and the high energy costs that currently exist argue against its implementation at this time. CPB claims that the program is not needed to provide safe and reliable service. It also claims that ratepayers would be required to pay its costs but the Company retains any resulting cost savings. CPB also asserts that this program may be inconsistent with the Commission's competitive metering agenda. Accordingly, CPB recommends that the pilot program be eliminated and any associated funds be used to mitigate the rate increases. [85]

CPB also takes issue with a provision that would allow the Company to reverse a ratepayer credit established when the Company failed to meet 2005 electric reliability targets. CPB claims that this result would not occur in a litigated proceeding and could reduce future incentives for utilities' compliance with regulatory standards and targets. [*61] [86]

CPB also opposes several retail access provisions, including the Market Match Program, Market Expo, Energy Fairs, ESCO satisfaction mechanism, ESCO ombudsman, competition awareness and understanding survey, the Competition Education

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[81] Tr. 742-744.

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[82] Tr. 744-747.

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[83] Tr. 748-750.

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[84] Tr. 750-755.

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[85] Tr. 756-757.

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[86] Tr. 757-758.

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Campaign, and the ESCO referral program. It claims that, with the exception of the Competition Education Campaign, the program costs are not quantified. With respect to the ESCO Referral Program, CPB asserts that there is an apparent lack of participation in the program and a failure to meet the requirement that at least two ESCOs participate. CPB asserts the revenue requirement impact of these provisions should be stated and the retail access provisions should be reduced by $ 100,000 each year. [87]

With respect to the $ 350,000 earmarked for the Competition Education Program, CPB **[*62]** asserts that there is no demonstration that previous retail access related outreach and education efforts have been cost effective. As a result of this omission and coupled with the alleged lack of ESCO interest in the ESCO Referral program, CPB recommends that the ratepayers fund no more than $ 175,000 annually for retail competition outreach and education programs. [88]

CPB also recommends that the any funds remaining in the electric depreciation reserve account be used to further moderate the proposed rate increases and the amortization of large and unusual losses that Central Hudson incurred in 2001 and 2002 on its retirement plan assets be extended. CPB asserts that both these proposals are fair to the company, in that they do not affect the company's earnings, and to ratepayers, in that they represent a better use of ratepayer money. [89]

[*63]

PULP

PULP opposes the Joint Proposal for failing to include utility-sponsored fixed price options and for an alleged improper use of ratepayer funds to promote private energy service company interests.

Observing that the July 2005 Order precludes Central Hudson from continuing to offer a fixed price option, PULP advocates an end to this prohibition. PULP contends that the fixed price option from the Company is preferred by residential customers and is highly valuable to low-income customers. Further, PULP asserts the discontinuance of this option was not necessary to support Commission policy, and reinstitution will not frustrate Commission policy. Consequently, PULP urges that the fixed price option be reinstated in time for the 2006-2007 heating season.

PULP also argues that ratepayer funds should not be used to promote retail access. According to PULP, it is unnecessary, and, in the context of the increases proposed here, unjustifiable. PULP states that, if such expenditures are allowed, they should be funded by energy service companies. [90]

[*64]

Select Energy

Select Energy opposes the balancing, cash-out and delivery proposals for service classifications 6, 12, and 13. It asserts that the method for monthly cashouts involves significant estimation and does not guarantee improvement over the current method. It claims that, because ESCOs are relying on the accuracy of such calculations, a monthly cashout program based on actual meter reads is preferable.

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[87] Tr. 758-762.

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[88] Tr. 762-765.

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[89] Tr. 766-767.

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[90] Ex. 64 at 2-3.

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Select Energy further contends that there are inequities between the proposed cashout index points for under-and over-deliveries in winter months. Specifically, it argues that the proposed under-delivery cashout ″defaults to the worst case scenario instead of actual costs″ and imposes costs on ESCOs that the Company may not have incurred. Select Energy states that Central Hudson only includes actual costs in its monthly supply costs and it should be required to do the same when assessing charges to ESCOs.

Select Energy asserts that the cashout proposal incorrectly assumes that customers have a 100% thermal response every month. It claims that the accuracy of the cashout proposal can be improved by implementing ″Monthly Thermal Response Adjustment Factors″ to account for **[*65]** a typical heating customer's response to heating degree days. It states that the implementation of such an approach should be delayed until appropriate studies can be performed.

Select Energy also opposes the incremental delivery requirement. Select Energy contends it is inequitable and discriminatory because the same requirements do not apply to sales customers and the incremental deliveries are used to balance Central Hudson's system without regard to actual usage. It also states that the requirement is unpredictable and nearly impossible for marketers to recover from customers. At a minimum, Select Energy argues that Central Hudson should be required to provide a quantitative analysis of when incremental deliveries required and a justification why individual marketers are required to makeup system shortfalls (typically during periods of maximum prices) without any regard for their actual consumption. Select Energy states that since ESCOs already pay for Storage Space, Storage Service, and Peaking Service that are used to balance the system on peak days, ESCOs should not be required to deliver incremental supply. [91]

[*66]

SCMC/RESA

SCMC/RESA take issue with the proposed hedging provision, alleging that it is at odds with Commission policy, acts to hinder competition and is inherently illogical. [92]

SCMC/RESA assert that the impact of existing or legacy hedges is reflected in the PPA, a rate design component that is charged on an equivalent basis to full service and retail access customers. SCMC/RESA state that this practice will be maintained for the legacy hedges, but all new hedges for small customers entered into after June 30, 2006 would be reflected in the Market Price Charge mechanism, a commodity charge that will be applied only to utility commodity sales customers. SCMC/RESA assert that this proposed rate design change is inequitable, anticompetitive and unreasonable, and should not be implemented.

SCMC/RESA urge the Commission to ensure that the reflection of utility hedging activity in rates is consistent with the utility's regulated monopoly advantages and is equitable to ESCOs and retail access customers. **[*67]** SCMC/RESA claim that the proposal to flow hedging costs through the Market Price Charge ignores the utility's overwhelming competitive advantage, as well as the fact that retail access customers, through their delivery rates, help sustain and fund utility hedging procurement activity.

SCMC/RESA claim that the utilities competitive advantage with respect to hedging was recognized and discussed by the Commission in connection with Central Hudson's fixed price option for gas. [93] SCMC/RESA assert that, if the Commission

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[91] Ex. 62.

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[92] Ex. 61 at 4.

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[93] Ex. 61 at 5-9.

allows the Company to reflect the cost of hedging practices in the commodity portion of the rate, it will reinforce the utility's market dominance and undermine the development of workable competitive playing field. [94]

SCMC/RESA further claim that retail customers, through their delivery rates, support and enable the utility to engage in hedging. SCMC/RESA conclude that, given this reality, it is unjust and unreasonable to direct that the impact associated [*68] with hedging procurement activities solely to full service customers by the commodity charge rate mechanism.

Finally, SCMC/RESA assert that if the Commission adopts the hedging provision and directs Central Hudson to reflect the impact of hedging activities only through the commodity charge, it will be difficult to achieve the eventual withdrawal of utilities from the business of hedging. [95]

Post-Hearing Briefs

Central Hudson

Central Hudson asserts that applicable requirements for a proposed settlement are fully satisfied here and that the opposition warrants no alteration. Central Hudson compares this proposal with recent rate plans for Consolidated Edison Company of New York, Inc. (Con Ed) and National Fuel Gas Corporation (NFG), and finds that the proposed revenue requirements, return on equity, equity ratio and earnings sharing provisions provide its customers with comparable, if not superior, benefits and protections. [96]

[*69]

With respect to the specific modifications suggested by the opponents, the Company first counters CPB and PULP's proposed fixed price offering. The Company asserts that CPB and PULP should not be allowed to collaterally attack the July 2005 Order directing the termination of its fixed price offering. Given the Commission requirement that proposed settlements conform to law and policy, the August 25, 2004 directive that "utilities should not propose fixed rate commodity tariffs" in future rate proceedings, and the specific directive of the July 2005 order, Central Hudson insists that the Joint Proposal correctly excluded a fixed price offer. [97]

The Company further insists that CPB and PULP's assertions about customer preferences for utility fixed price offers are unsubstantiated and lack empirical evidence demonstrating market failure. According to the Company, the Joint Proposal allows the market to function; altering it to require fixed price offerings by the Company [*70] would severely wound the competitive market. [98]

The Company contests CPB's recommendation to reduce capital expenditures, stating that CPB has not proposed specific quantitative levels. The Company also argues that the CPB formula for setting a revised level of capital expenditures is arbitrary because it is divorced from any assessment of need. The Company asserts that the proposed expenditure levels

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[94] Ex. 61 at 10-11.

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[95] Ex. 61 at 11-15.

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[96] Central Hudson Post-Hearing Brief, Revised June 5, 2006 at 2-7.

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[97] Central Hudson Post-Hearing Brief at 7-8.

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[98] Central Hudson Post-Hearing Brief at 7, 10.

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were carefully and thoroughly reviewed by Staff and Company engineers and revised upward to include additional funds for necessary gas infrastructure enhancements. [99]

Central Hudson argues against CPB's proposal to true-up distribution ROW maintenance expenditures. The Company asserts that the scope of the program has not changed and history shows it expended **[*71]** more than was allowed in rates. The Company further argues that CPB's analysis erroneously excluded the enhanced tree trimming costs which undercuts its premise for a true-up mechanism. Finally, the Company contends that the reliability penalties already address the possibility that ratepayers could be short-changed by any underspending. [100]

The Company considers CPB's adjustment to storm expenditures an attempt to cast aside the time proven methodology. It says that CPB's testimony on this issue is varied and internally inconsistent. The Company urges rejection of CPB's proposal for MGP and SIR costs, stating that it is inconsistent with applicable policy. It also urges the rejection of CPB's discount rate for pension and OPEB expenses, noting that the support provided is CPB's initial brief in a currently ongoing NYSEG case in which the Company (NYSEG) and Staff agreed to the same 5.5% discount rate proposed here. [101]

[*72]

Central Hudson asserts that CPB's proposal to decrease an already low ROE is unreasonable. It claims that CPB failed to update its own recommendations, and that, given CPB's concession that Con Ed and Central Hudson face the same risks, it is promoting discrimination by advocating a lower ROE for Central Hudson (8.84%) than it previously supported for Con Ed (10.3%). The Company continues that CPB misapplies the Generic Finance Case principles related to stay-out premiums. [102]

Central Hudson claims that in the event of future pension plan revisions, certain cost differentials would be captured and available for future disposition by the Commission. It therefore concludes that CPB's proposal regarding supposed cost savings from a change in the current pension plan is inconsistent with the Commission Policy Statement and is premature.

Central Hudson claims that CPB's objections to the proposed metering pilot lack foundation because no funds have been actually committed **[*73]** to it and it would proceed only if ultimately approved by the Commission. The Company discounts CPB's opposition to the reversal of the 2005 electric reliability penalty, stating CPB failed to recognize the provision in context with other interrelated provisions. [103]

Central Hudson claims that CPB and PULP's challenges and proposed modifications to the retail access provisions lack justification and evidentiary support, and are inconsistent with Commission policy. The Company continues that the levels of these expenditures are addressed by the proposed deferral mechanisms. [104]

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[99] Central Hudson Post-Hearing Brief at 10-12.

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[100] Central Hudson Post-Hearing Brief at 14-17.

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[101] Central Hudson Post-Hearing Brief at 18-21.

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[102] Central Hudson Post-Hearing Brief at 22-25.

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[103] Central Hudson Post-Hearing Brief at 25-27.

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[104] Central Hudson Post-Hearing Brief at 27-30.

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Central Hudson asserts that CPB's proposals for additional rate mitigation ignore the nature of excess reserve and the increased risk of future, possibly major rate increases [*74] that could flow from a decision to deplete the excess reserve. The Company also claims that CPB's proposal to extend the amortization of pension losses contradicts applicable policies. [105]

Central Hudson asserts that SCMC/RESA's understanding of the current treatment of legacy hedges is inaccurate, noting that while Constellation hedges are flowed through the PPA, Entergy hedges are flowed through the Market Price Charge to electric commodity sales customers only. Thus, Central Hudson denies that the proposal to flow post-June 30, 2006 hedges through the Market Price Charge to electric commodity sales customers is a rate design change or is inequitable, anti-competitive or unreasonable. Instead, the Company asserts that the proposed treatment accords with Commission policy articulated in the Retail Energy Markets Policy Statement and warrants no alteration. [106]

[*75]

Finally, with respect to the proposed gas balancing provisions, Central Hudson again argues that no alteration is warranted because the proposed formula prevents gaming and is similar to provisions included in the NFG rate plan. [107]

Staff

Staff urges rejection of the opponents' positions and adoption of the proposal without modification.

Staff claims that CPB's modifications should be rejected because they would fundamentally alter the proposal's balancing of ratepayers and shareholders interests, and are premised on misunderstandings and misstatements. Staff insists that the available choice is between the proposed rate plan and a litigated one-year rate determination. Staff contends that CPB's approach would lead to the latter result and asserts that CPB has not demonstrated that its one-year rate determination is superior to the Joint Proposal.

Staff asserts that, if CPB's approach prevails, many of the proposed plan's benefits, including promotion of retail access [*76] policies, rate unbundling, inauguration of gas balancing and cash-out procedures, a new low-income program that reflects best available practices, spending necessary to ensure safe and reliable service, and resolution of a complex dispute between Central Hudson and USMA, would be lost, replaced by a series of litigated one-year rate proceedings where substantial rate increases would still be needed. Staff argues that since the proposed plan funds all reasonably expected costs and leaves no hidden costs, it could continue beyond its term, extending the time ratepayers and the Company would realize the benefits of stable rates. [108]

With respect to specific items, Staff asserts that CPB's and PULP's arguments on a tariffed fixed-price option raise issues that were recently decided and are beyond the scope of these proceedings. Staff adds that reinstituting a fixed price offer is short-sighted and would engender long-term harm to consumers, especially low-income [*77] customers. [109] Staff further

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105 Central Hudson Post-Hearing Brief at 30-32.

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106 Central Hudson Post-Hearing Brief at 32-33.

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107 Central Hudson Post-Hearing Brief at 32.

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108 Staff Post-hearing Brief, dated May 12, 2006 at 2-6.

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109 Staff Post-hearing Brief at 2, 7.

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contends that CPB and PULP have not undermined the reasons for terminating Central Hudson's fixed price option. Staff notes that Central Hudson's fixed price option was subsidized by other customers, rendering its design unjust and unreasonable. Staff also notes that the fixed price option distorted and retarded the development of the retail market to customers' disadvantage. Staff claims that CPB and PULP have not refuted the July 2005 Order's analysis of these points.

Staff asserts that there is no demonstrated need or established design parameters for a utility fixed price option. Staff notes that fewer than 2,000 customers (less than 3% of the customer base) subscribed to Central Hudson's 2002-03 fixed price option, and, even at its peak, it attracted fewer than 10,000 of Central Hudson's gas customers (less than 15% of its total eligible customer base). Staff notes CPB's acknowledgment that the fixed price option price could exceed standard **[*78]** tariff rates. Staff further states that, if prices have stabilized, reinstituting a fixed price option is an unnecessary response to a problem that no longer exists. Staff further suggests that, as has happened in the past, interest in the fixed price option would quickly evaporate when prices cease rising. [110]

Staff argues that CPB and PULP's proposed fixed price option is insufficiently detailed and cannot be successfully implemented. Staff asserts that CPB's position that the fixed price option cannot be subsidized and cannot allow for any utility profit ensures that it will be unworkable or unduly expensive. Staff asserts it is unworkable, in part, because, its proponents acknowledge that the hedging required to offer the option creates volume and price risk, but fail to explain how such risk would be treated. [111]

[*79]

Staff also contends that the detrimental impacts that could result in the likely event of a fixed price option price substantially exceeding the standard tariff price are ignored. Staff also argues that CPB and PULP have not meaningfully challenged the impact of a utility-provided fixed price option on competitive markets, even though they were identified and discussed in the July 2005 Order. Staff claims that instead of addressing such impacts, CPB and PULP make unfounded criticisms that the competitive market has failed to respond adequately. Staff says their criticisms are belied by the fact that ESCOs offered fixed price options and nearly 25% of customers availed themselves of such opportunities. Staff asserts that the competitive marketplace can tailor offerings that better meet consumers' needs at reasonable prices, but only if CPB and PULP's proposal is rejected. [112]

With respect to CPB's opposition to the proposed levels of safety, reliability and environmental spending, **[*80]** Staff states that CPB erroneously claims that the proposed capital expenditures exceed the levels proposed by any party. Staff responds that the capital expenditures are taken directly from the Company's evidentiary presentation, and are increased by $ 1.2 million for additional gas reliability expenditures and adjusted to reflect the increasing amounts Central Hudson has actually spent in recent years. [113]

Staff also argues that CPB misses important connections between the capital budget spending and forecasts of utility activity (e.g., between one-third and one-half of gas capital expenditures for Rate Years 1 through 3 are dedicated to the facilities needed to extend service to new customers) . Staff, like the Company, asserts that CPB has not connected its proposed expenditures to levels needed to preserve safe and reliable service. Staff asserts that as a result of these and other errors, CPB's proposal is unreasonable.

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[110] Staff Post-hearing Brief at 8-10.

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[111] Staff Post-hearing Brief at 10-12.

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[112] Staff Post-hearing Brief at 12-15.

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[113] Staff Post-hearing Brief at 16-17.

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Staff asserts that similar errors afflict CPB's [*81] ROW and storm cost analyses. Staff claims that CPB excludes distribution ROW expense expenditures that were funded through the Benefit Fund and disregards the most recent data on storm costs.

Staff claims that CPB's arguments regarding the treatment of MGP remediation expense are incorrect, noting that, contrary to CPB's assertions, the existing approach to MGP expense and the related requirements of prior orders would continue. Staff also argues that CPB, in its effort to shift some MGP expense to Central Hudson, overlooks binding orders and instead points to outmoded precedents that do not favor a clean environment.

Staff argues that CPB's deferral proposals are factually inaccurate and reflect a misunderstanding of the Joint Proposal's capital budget and ROW expense deferral-based incentive mechanisms. Staff explains that under the proposed rate plan, if Central Hudson fails to achieve a targeted level of capital expenditure or transmission ROW expense, the difference is deferred for ratepayer benefit. Staff contends that, since these expenditures are needed to preserve safe and adequate service and since electric reliability at Central Hudson has fallen below acceptable levels [*82] in recent years, every effort should be made to encourage the utility to actually expend those funds. Staff claims that CPB's proposed substitute, which would allow Central Hudson to defer capital and ROW expenditures that exceed CPB's targets, might actually discourage improved reliability because the expenditure levels CPB proposes are insufficient and Central Hudson might not see an incentive sufficient to warrant the expenditure of funds that exceed the inadequate allowances. [114]

Staff asserts that it has fully justified moving from its initial 8.65% ROE position to the proposed 9.6% ROE. Staff explains that Central Hudson's parent, CH Energy Group, Inc., was removed from the proxy group of companies considered comparable to Central Hudson because it yielded uncharacteristically low returns in comparison to the other utility companies in the proxy group. Staff states that the 8 basis point adjustment revised the weighting of the zero beta CAPM calculation in the overall [*83] ROE determination from 25%/75% to 50%/50%, which it notes is within the range of previously-accepted weightings.

Staff argues that its stay-out premium is reasonable and that CPB's arguments to the contrary rely upon a misunderstanding of the Generic Finance Case methodology, which is not binding in any event. Staff asserts that the difference in the yield between one-year and three-year U.S. Treasury Securities is sufficient to support its risk adjustment for a three-year plan. Moreover, Staff argues that this three-year plan is eligible for a stay-out premium because its prices are set and not updated, and the Generic Finance Case methodology provides an approach to calculating the stay-out premium that yields 38 basis points. [115]

Staff urges rejection of CPB's arguments concerning pension and OPEBs. Staff asserts that updating the discount rate now would be superfluous since the rate will be updated when a new actuarial report is filed in January 2007. Staff adds that an [*84] earlier update would be immaterial in the context of the overall expense. [116]

As to the length of the deferral period, Staff claims that extending it conflicts with the Pension and OPEB Statement and Order, [117] and might also result in inter-generational inequities.

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[114] Staff Post-hearing Brief at 17-20.

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[115] Staff Post-hearing Brief at 22-24.

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[116] Staff Post-hearing Brief at 25.

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[117] Case 91-M-0890, <u>Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions (OPEB)</u>, Order and Statement of Policy Concerning Pension and Other Post-Employment Benefits (issued September 7, 1993).

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In response to CPB and PULP's claims that retail access expenditures are excessive, Staff insists such spending has been constrained to the levels that are necessary to implement Commission policies. Responding to CPB's claim that the expenditures related to the ESCO Referral Program are questionable because **[*85]** the program has not yet commenced operations, Staff asserts that the program has been successfully launched, and that initial indications are that it will achieve its intended objectives. In addition, Staff notes that the Commission has repeatedly expressed its support for ESCO referral programs and rejected all objections to their implementation only six months ago. [118]

Staff asserts that CPB's arguments against the proposed metering were rejected in the 2004 Rate Plan Order. Staff contends that the proposed metering initiative is a reasonable use of funds reserved therefor and is in conformance with the prior rate orders. [119]

[*86]

As to CPB's opposition to excusing Central Hudson from making the 2005 reliability adjustment, Staff reiterates that both the 2001 and 2004 Rate Plan Orders authorize Central Hudson to excuse a failure to satisfy reliability targets if it could show that its OMS introduction was at the root of its compliance failures. Staff notes that Central Hudson repeatedly maintained that installation of the OMS system adversely affected its ability to meet reliability targets in 2005, 2004 and 2002 and has complied with the prior orders. Staff contends that the Joint Proposal also complies with the prior orders because it provides for payment of the 2004 and 2002 rate adjustments, and excuses only the 2005 adjustment. [120]

Staff notes that, in order to further mitigate the proposed electric rate increases, CPB would entirely deplete the remaining $ 20 million of excess depreciation reserve. Staff argues that CPB incorrectly presumes $ 20 million would reduce the electric rate increases **[*87]** by approximately $ 6 million each rate year. Staff asserts that in order for CPB to achieve the reductions it apparently intends, about $ 36 million in rate moderators would be required. Staff also claims that the associated rate decreases would be of minimal benefit. Staff concludes that the excess electric depreciation reserve balance is best retained to offset future deferrals that are difficult to forecast. [121]

Staff asserts that SCMC/RESA's position that Central Hudson should recover the hedging costs for its smaller customers' supply through delivery rates, rather than commodity rates contravenes applicable policy and would dilute the hedge's value. Staff notes that SCMC/RESA misunderstand the current treatment of existing hedges. It states that only the Constellation hedge, a legacy of the divestiture of Central Hudson's generation plant, is recovered from all ratepayers, while the existing Entergy hedge, entered into after divestiture and unrelated to it, is recovered only **[*88]** from commodity customers, in conformance with the 2004 Rate Plan Order. [122]

With respect to Select Energy's position that use of Central Hudson's actual gas costs for pricing purposes would be preferable to the use of an index for pricing under-deliveries during the winter, Staff notes that winter under-deliveries can threaten system reliability. Staff asserts that use of an index to determine the pricing for under-deliveries results in setting

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[118] Case 05-M-0858, <u>State-Wide Energy Services Company Referral Programs</u>, Order Adopting ESCO Referral Program Guidelines and Approving an ESCO Referral Program Subject to Modifications (issued December 22, 2005).

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[119] Staff Post-hearing Brief at 26-28.

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[120] Staff Post-hearing Brief at 28-30.

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[121] Staff Post-hearing Brief at 31.

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[122] Staff Post-hearing Brief at 31-32.

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that price at the marginal cost of additional gas supply. Staff continues that marginal cost pricing is the appropriate reference point because if additional supplies were suddenly needed, the price charged would be at marginal cost rather than at the utility's average cost.

Staff states that Select Energy's proposed gas balancing mechanism response adjustment factors disregard of the difficulties that may attend the calculation, billing and implementation of such factors. Staff asserts that the development and consideration of appropriate [*89] factors for Central Hudson should wait for a time following successful implementation of the proposed gas balancing procedures.

In response to Select Energy's opposition to the incremental delivery requirement, Staff says that the requirement is essential to preserving system reliability and the suggested alternative won't work given current metering. [123]

Multiple Intervenors

Asserting that the Joint Proposal represents an integrated whole, reflecting numerous compromises by parties with diverse and often adverse interests, Multiple Intervenors reiterates it should be adopted without modification.

With respect to the proposed electric revenue allocation and rate design, Multiple Intervenors asserts that the testimony and exhibits of Dr. Rosenberg support those provisions. They argue that, based on their witness' testimony, as well as that proffered on revenue allocation and rate design issues by Central Hudson and Staff, the provisions addressing those issues are reasonable [*90] and well within the range of likely litigated outcomes. Multiple Intervenor observe that none of the opponents challenged the electric revenue allocation and service classification 3 and 13 rate design and concludes that those provisions should be evaluated as negotiated, uncontested provisions with ample record support.

DOD

DOD reiterates its request for adoption of the Joint Proposal, asserting that it provides a reasonable resolution of these proceedings. DOD argues that, in addition to resolving numerous and complex issues in these rate cases, the Joint Proposal addresses many details regarding the provision of gas transportation for USMA at West Point and use of the USMA gas distribution system for service to Central Hudson's customers in Highland Falls, New York. DOD asserts that the provisions relating to USMA are just and reasonable and should provide a constructive and stable basis for the provision of gas to USMA and other affected customers. DOD notes that there is no opposition concerning these provisions. [124]

[*91]

CPB

CPB asserts that these proceedings provide an opportunity to address the impact of near-record high commodity prices and the largest delivery percentage rate increases to be proposed for any major energy utility in more than a decade.

CPB argues that the Joint Proposal as presented does not satisfactorily address the impact of higher commodity prices, does not provide for measures that would properly respond to today's circumstances, and does not adequately reflect consumer interests. It continues that it does not satisfy the Commission's Settlement Guidelines, nor question whether policies and practices that may have been common before are appropriate now. CPB states the proposal contains some positive

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123 Staff Post-hearing Brief at 32-35.

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124 DOD's letter in lieu of brief, dated May 12, 2006.

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elements, like the phase-in of rate increases, the low-income program and the exclusion of the retail access incentive, but overall, is not in consumers' interest. [125]

CPB alleges that the Joint Proposal has not earned the support of normally adverse [*92] parties, particularly CPB and PULP. It discounts the support of Multiple Intervenors, claiming it is due exclusively to the resolution of electric revenue allocation, electric rate design, and gas balancing and revenue allocation issues. It also discounts DOD's support, contending it is due only to the resolution of disputes regarding service to one customer. [126]

CPB argues that the context for this proposal must be carefully considered. It urges consideration of policies it says deny customers the opportunity to purchase commodity from the utility at fixed prices, enable the utility to retain ratepayer funds for unspecified purposes and unspecified periods of time, require ratepayers to fund projects that are not necessary for safe and reliable service and permit unreasonably large increases in certain expense categories that are inappropriate at this time. CPB argues for focusing on the overall increases in delivery rates, not the impact on total bills. [127]

[*93]

CPB denies implications that its position in these proceedings is contrary to the position it took in a case involving Con Ed, stating that it did not support that proposal either and, as here, submitted a statement to help identify and explain the pro-consumer provisions. CPB asserts that its panel testimony acknowledges that consideration should be given to the fact that Central Hudson's base delivery rates have not increased in many years, but it also clearly explains that the benefit of past rate freezes cannot properly be considered as a benefit of this proposal and that the presence of some pro-consumer provisions does not mean that overall, the public interest is satisfied.

CPB asserts that it has demonstrated consumers need new tools to help them manage high and volatile energy prices, including a fixed price option from the utility and reliable information from the utility on the reasons for high prices, conservation, and the availability of assistance programs, neither of which, absent any record basis, is provided. [128]

[*94]

In response to Company and Staff assertions that (1) the Commission directed Central Hudson to terminate its fixed price option and (2) this issue cannot be relitigated in this proceeding, CPB asserts that New York State Public Service Law and relevant New York State case law indicate that there is no legal prohibition against considering fixed price proposals in this proceeding.

As a threshold matter, CPB states that Company and Staff failed to recognize that the July 2005 Order applies only to gas and that no such order applies to an electricity fixed price option offered by Central Hudson. CPB adds that the issue of whether adequate electric service by Central Hudson requires offering a fixed price option for electricity has not been litigated before the Commission. [129]

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[125] CPB Post-hearing Brief, dated May 12, 2006 at 1, 5-6.

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[126] CPB Post-hearing Brief at 2-4.

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[127] CPB Post-hearing Brief at 4.

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[128] CPB Post-hearing Brief at 6.

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[129] CPB Post-hearing Brief at 7.

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CPB also points out that applicable rules expressly provide that "[t]he rates, rules and regulations relating thereto that are in effect when the proceeding is initiated will not be presumed to be just and reasonable." [*95] It therefore contends that when Central Hudson filed its rate case, all of its rates, rules and regulations became open to reconsideration. CPB asserts that, by the Company's logic, the SCMC/RESA Petition should never have been considered because the issue had already been determined in a previous order. CPB states that the Commission, as a policy making entity, always has the discretion to examine and modify rate policies as it sees fit, a fact that its regulations for rate cases make explicitly clear. [130]

CPB also argues that attempts to bar its fixed price option testimony through collateral estoppel must fail because (1) the collateral estoppel doctrine can only be utilized by a party after establishing that the issue in the present proceeding is identical to that necessarily decided in a prior proceeding, and that in the prior proceeding the party against whom preclusion is sought was accorded a full and fair opportunity to contest the issue and (2) it usually is not applied [*96] unless the administrative decision was quasi-judicial in character and thus is not applied when an agency acts in a ratemaking capacity. CPB argues that the July 2005 Order constituted ratemaking and therefore can not be granted preclusive effect. CPB further asserts that in administrative proceedings, the proponent, in this case Central Hudson, bears the burden of identifying the issues as identical, and that burden was not met here. [131]

CPB counters Company and Staff assertions that the record does not support the adoption of its proposal by citing a recent study's finding that consumers without substantial financial assets decrease spending on items such as food by 40 cents for each unanticipated dollar increase in their home energy bill. CPB cites to its panel testimony for evidence that the availability of a reasonably priced fixed price option would provide a valuable tool to help avoid this scenario. CPB acknowledges that a utility fixed price option will not necessarily [*97] decrease bills but maintains it is a tool that should be available to help consumers manage volatile energy bills.

CPB asserts that it demonstrated that ESCO fixed price options are not reasonably priced and that ESCO products that are so-identified may in fact permit the ESCO to increase the price without recourse by the customer. CPB continues that of the 8,504 customers who subscribed to Central Hudson's gas fixed price option when it was terminated on October 1, 2005, only 21% had chosen ESCO service six months later. According to CPB, this record evidence demonstrates that the vast majority of fixed price customers in Central Hudson's territory would rather pay the utility's variable price than take service from an ESCO. [132]

CPB also claims to have demonstrated that its proposal is consistent with the Commission's orders on retail competition. It asserts that, since the competitive market has not responded adequately and Central Hudson can be distinguished from other utilities, [*98] the Commission has new facts and circumstances to consider in evaluating utility fixed price options. CPB adds that, contrary to Staff assertions, there is no Commission directive against utilities offering fixed price products. [133]

CPB reiterates that consumers should be provided accurate and timely information on the cause of high energy prices, actions they can take to manage their energy bills, and how to obtain assistance in paying their bills. CPB argues that the

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[130] CPB Post-hearing Brief at 8.

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[131] CPB Post-hearing Brief at 7-11.

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[132] CPB Post-hearing Brief at 12-13.

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[133] CPB Post-hearing Brief at 13. CPB cites to the NYSEG and RG&E FPO offerings and to Case 00-M-0504 (Statement on Policy on Further Steps Toward Competition in Retail Energy Markets (issued August 25, 2004), page 3) to support its assertions.

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fact that CPB and Staff played key roles in delivering such information to consumers this past winter, demonstrates that such information can be delivered to consumers without interfering with the Commission's competitive agenda. [134]

[*99]

In response to proponents' claims that using electric reserve depreciation to further mitigate the proposed rate increases would set the stage for rate increases after the funds expire, CPB insists there is no better use for such funds. CPB further claims that the two potential uses for this surplus that are set forth in the Joint Proposal either should not be conducted at this time (i.e., the AMR pilot) or are minimal (i.e., covering cost of electric backout credits). [135]

CPB states that, in the current environment of high energy prices and a proposed series of large delivery rate increases, the Commission should carefully consider the appropriateness of funding any projects - like the AMR pilot, retail access programs, and the Competition Education Campaign. CPB claims that its testimony in this regard was not challenged on cross examination. [136]

[*100]

CPB claims the Company's recent capital spending trends belie Staff and Company claims that spending increases are necessary for safe and reliable service, particularly since the Company's electric system earnings exceeded the sharing thresholds in the years 2001-2005.

CPB states that even though it now understands that the Joint Proposal reflects a projected increase of $ 5.571 million (126%) in annual ROW maintenance spending beyond 2005 levels (about 2% less than the Company's request in initial testimony), it remains concerned that an increase of this magnitude may not be necessary, may not be spent in a cost effective manner, or may not be spent at all. It therefore adheres to its ROW recommendations. CPB contends that its proposed measures are necessitated by the magnitude of the projected spending (even under its proposal), and by the high degree of uncertainty concerning the appropriate level of such spending. CPB notes, that in 2005, the Company chose to spend less on ROW maintenance than it had in any year since before 2000, even though it had excess earnings and failed to meet minimum reliability standards in 3 of the last 4 years. It also highlights Staff testimony that **[*101]** there is no disadvantage to proposed shortfall mechanism.

With respect to storm expense, CPB adds to its previous arguments its assertion that the proponents failed to meet their burden to demonstrate that the reasonableness of the proposed costs. [137]

In response to the proponents' challenge to its position regarding the reversal of the 2005 reliability penalty, CPB responds that that it is unlikely that the Commission would have reversed its order regarding the 2002 and 2004 penalty, but the Joint Proposal guarantees that the Company could avoid any consequences for its failure to meet applicable 2005 standards.

CPB reiterates that shareholders should bear some portion of the MGP costs. It reasons that ratepayers were not responsible for the Company incurring those costs; the expenses at issue are extremely large; it is important to constrain rates; and the Company should be provided an incentive to seek recovery of these expenditures from other responsible parties. CPB also

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[134] CPB Post-hearing Brief at 13-14.

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[135] CPB Post-hearing Brief at 15-16.

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[136] CPB Post-hearing Brief at 16-20.

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[137] CPB Post-hearing Brief at 24-25.

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[*102] claims that no party challenged its proposal on cross examination. [138]

With respect to changing the pension and OPEBs discount rate to 5.75%, CPB claims that, unlike the Company, it used the most recent data available to calculate its recommended rate. CPB also counters the proponents' assertion that large pension and OPEB expenses are inevitable with its claim that the Joint Proposal does nothing to prevent such a situation from recurring. CPB claims despite the trend away from defined benefit plans, if the Company transitions away from defined benefit pension plans in the next three years as expected, the Joint Proposal would allow it to retain all associated savings. CPB asserts that its proposal to capture any such savings is consistent with the outcome in competitive markets, is fair to the Company and would help reduce the likelihood that Central Hudson will request another large rate increase based primarily on the need to fund employee pensions.

With respect to ROE, CPB [*103] clarifies that, with the exclusion of the adjustments to account for interest rate changes or to reflect 2005 as the starting point for calculating the stock valuation adjustment, the proposed adjustments should not be adopted. It maintains that use of Generic Finance Methodologies results in a cost of equity of approximately 8.95% for Central Hudson.

Specifically, CPB claims that removal of CH Energy Group from the proxy group is atypical, was not made in the Generic Finance case, and both Central Hudson and Staff included CH Energy Group in their proxy groups in this proceeding. CPB adds that changing the weighting of the Traditional and Zero-Beta Capital Asset Pricing Model ("CAPM") from 75/25 to 50/50 is contrary to the approach taken in the Generic Finance case, which has been used in most cases approved by the Commission. Finally, CPB asserts that a stayout premium is inappropriate here because the revenue requirement calculations under the Joint Proposal are essentially equivalent to three one-year rate cases, which would not get a premium under the Generic Finance Case methodology. CPB asserts that the record establishes that removing the results of Consolidated Edison and [*104] two other companies from Central Hudson's DCF estimate in these circumstances, as the Company did, was completely arbitrary and served no other purpose but to inflate the Company's estimates.

Finally, with respect to possible further rate increase mitigation, CPB reiterates its claims that extending the amortization of large and unusual losses incurred by Central Hudson in 2001 and 2002 on its retirement plan assets for an additional 10 years is within the Commission's authority and should be considered if additional rate mitigation is appropriate. [139]

PULP

In its post-hearing brief, PULP reaffirms its opposition to the Joint Proposal, citing the absence of a fixed price option and the proposed retail access expenditures.

At the outset, PULP argues that the motion, made by the Company and supported by Staff, to remove the fixed price option proposal was unjustified and untimely. PULP asserts that, even if the motion could be justified, it should have been made when the proposal [*105] was first advanced in CPB's November 2005 testimony. PULP adds that even if the "surprise" motion had been timely, it would have failed because (1) the CPB and PULP proposal is to establish fixed price options for gas and electric service, while the July 2005 Order and the underlying petition addressed gas only and (2) the information provided here in support of the fixed price offer proposal is information which was unavailable to the Commission at the time of its July 2005 decision. [140]

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[138] CPB Post-hearing Brief at 26-27.

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[139] CPB Post-hearing Brief at 27-33.

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[140] PULP Post-hearing Brief, dated May 12, 2006 at 3, n. 3.

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PULP argues that this record establishes several reasons why the decision in to terminate the fixed price option should be evaluated anew. PULP cites a discovery response provided by Central Hudson which reports that over 8,500 customers were purchasing gas under its fixed price option in October 2005. [141] PULP notes that under the then-applicable Central Hudson tariff, customers could only receive such service if they affirmatively sought it prior to the heating season. [*106] PULP thus concludes that thousands of customers demonstrated in the clearest possible way that they wished to receive gas service from Central Hudson under a fixed price option. [142]

PULP argues that unrefuted data shows that after the discontinuance of the fixed price option, over 6700 of the 8500 customers who had been taking the Central Hudson fixed price offer continued as Central Hudson customers. PULP thus concludes that even when their preference is eliminated, these customers choose not to move to an ESCO supplier. PULP contends that renewal of the offer of a fixed price option from Central Hudson will provide these customers with ″what they want - a fixed price option from their chosen supplier - Central Hudson.″ PULP claims that refusal to provide a fixed price option from Central Hudson is a market failure.

PULP further asserts that the continued unavailability of a fixed price option from Central Hudson is [*107] not necessary to implement a Commission policy. PULP claims that since customer migration after the elimination of the fixed price option from Central Hudson did not materially increase the number of customers taking commodity service from ESCOs, its reinstitution will not materially reduce the number of customers who may switch to ESCOs.

PULP also argues that, at the time of the July 2005 Order, the Commission believed that seven or more ESCOs would be making fixed price offers to residential customers in the Central Hudson service territory, and that, as of May 2, 2006, actual numbers were far less than the Commission anticipated in July. PULP asserts that this reason alone should warrant reconsideration of these issues. [143]

PULP adds that the record now shows that the fixed price offers that are available to residential consumers do not actually provide a fixed price. It asserts that the purpose of a fixed price offer is to shift the risk of commodity price fluctuation from [*108] the customer to the commodity supplier. PULP claims that the contracts used by the four ESCOs identified as providing a fixed price offer to residential gas customers provide the ESCO with one or more escapes. [144] PULP claims that there is no indication that the Commission was aware in July 2005 of these types commitments and, had it known of them, it could not have concluded that the ESCO's fixed price offers were comparable to the Central Hudson's. PULP concludes that, with the information now in this record, reestablishing the Central Hudson fixed price offer as soon as possible is fully justified. [145]

PULP, like CPB, refers to an April 2005 research paper concerning [*109] the harmful effects that volatile energy prices can have for low-income households to argue that record in this case now shows that the absence of a fixed price offer for residential customers is particularly harmful to Central Hudson's low income customers. [146] PULP states that the April 2005 paper analyzes data over a 12 year period from more than 50,000 households and shows that, for most customers,

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141 PULP Post-hearing Brief at 4, citing Ex. 67, Sch. 2.

142 PULP Post-hearing Brief at 4.

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143 PULP Post-hearing Brief at 5-6.

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144 PULP Post-hearing Brief at 7. PULP states that the four ESCOs making a fixed price gas offer to the Central Hudson residential customers were and are Intelligent Energy, Interstate Gas Supply, MXenergy, and Energetix, while the one ESCO providing a fixed price electricity offer was and is Accent Energy.

145 PULP Post-hearing Brief at 8-10.

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146 PULP Post-hearing Brief at 11.

a sharp rise in energy costs will be met from savings or by lengthening their credit card or other credit accounts. PULP states that low income customers, however, cannot respond to sharp rises in energy costs in this way, so they will meet the energy cost crisis by reducing consumption of other necessities. PULP argues that for these customers, a fixed price offers some assurance that volatile energy bills will not become a source of life threatening instability. PULP contends that since this research had not been made available last July, it also represents new information that warrants reconsideration of the availability of utility fixed price options. [147]

[*110]

With respect to the Joint Proposal's proposed funding for retail access programs, PULP observes that support for retail access will increase from $ 250,000 per year to $ 350,000 per year. PULP notes that previous such expenditures were funded from a Benefit Fund and, as such, did not directly impact rates. Now that the Benefit Fund has been exhausted, PULP concludes that these expenditures now will have a direct impact in raising customer rates and bills. PULP contends that when revenue requirements are rising at double digit rates and both gas and electric customers will see dramatic price increases, the continued and increased expenditure of ratepayer funds cannot be justified. [148]

PULP argues that the Market Match and Market Expo programs, Energy Fairs, ESCO/Marketer Satisfaction Survey, ESCO ombudsman and Competition Outreach and Education Program, **[*111]** individually, and as a group, are intended solely to give ESCOs better access to customers or to ease or facilitate their participation in the service territory. PULP adds that there is no indication that any of these programs have a material effect on residential customers' migration to ESCO service. PULP contends that these programs have been operating at least since July 2004, but as of November 2005, less than 800 residential customers had migrated to ESCO service. PULP further contends that, while the number of migrating customers increased to just over 5200 in March 2006, this corresponds to the dramatic increase in energy prices over this past winter, and not to these programs. PULP states that, in the absence of easily obtainable data showing actual bill impacts of ESCO service as compared to utility service, it must be assumed that residential customers have not benefited significantly, or at all, from their decision to take ESCO service. PULP thus concludes that use of ratepayer funds to promote retail access cannot be justified. [149]

[*112]

PULP claims that, as a new program, the overall effectiveness of the Energy Switch program cannot be adequately judged. PULP adds, however, that what can be determined is that its costs are excessive. PULP calculates that, under this program, a minimum of $ 1750 is spent per day, to recruit, on average, 5 customers per day for ESCO service (or $ 350 per switched customer) . PULP states that the savings for these customers is limited in this program to 7% of the Central Hudson bill for two months, which it calculates would be $ 18.55 and $ 11.06 per month for typical gas and electric non-heating customers, respectively. PULP concludes that any money spent by Central Hudson in support of the residential retail access program should be recovered from the ESCOs participating in that program and that any ratepayer funds supporting the retail access programs should be removed and corresponding reductions made to revenue requirement and rates. [150]

SCMC/RESA

SCMC/RESA respond to **[*113]** the CPB and PULP's assertions that a utility-sponsored fixed price option should be reintroduced by claiming it is unnecessary, unreasonable and inconsistent with established Commission policy.

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[147] PULP Post-hearing Brief at 11-12.

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[148] PULP Post-hearing Brief at 12-13.

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[149] PULP Post-hearing Brief at 13-15.

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[150] PULP Post-hearing Brief at 15-16.

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SCMC/RESA cite to the Commission's Statement of Policy governing the implementation of competition in retail markets, specifically its requirement that ". . . in future rate proceedings, utilities should not propose fixed rate commodity tariffs or tariffs creating a profit center for commodity sales." [151] SCMC/RESA argue that the Commission has repeatedly underscored the position that ESCOs rather than regulated utilities should be providing fixed price service.

SCMC/RESA declare that the assertion that a fixed price option is needed as a "bulwark" against rising energy cost is simplistic and unrealistic. [152] SCMC/RESA assert that historic data does not support the view that a fixed price option will better shield customers from the impact of rising **[*114]** energy prices than variable rates. SCMC/RESA cite as an example, the existing NYSEG's rate plan, claiming that NYSEG's variable rate has generally been lower than its fixed price option. SCMC/RESA expressly counter the CPB and PULP claim that the levels of migration show a preference for a utility-sponsored fixed price option, stating that the numbers could just as easy represent a conscious choice by customers to accept pricing variation instead of the higher costs associated with a fixed price option.

SCMC/RESA contend that the Joint Proposal contains recommendations (e.g., a portfolio purchasing strategy, including hedging) that have the potential to moderate swings in supply costs. SCMC/RESA also note the availability of budget billing, as authorized by law, which affords customers the opportunity to pay an equivalent amount each month for energy charges.

SCMC/RESA argue that criticism of the ESCOs' fixed price offerings is misguided. SCMC/RESA further assert **[*115]** that ESCOs will respond to market conditions and customers preferences, and will provide products in accordance with the demand therefor. [153]

With respect to retail access funding, SCMC/RESA claim that proposals to reduce such expenditures are short-sighted and should be rejected. SCMC/RESA assert that competitive choice should be promoted and aggressively pursued as a means of helping customers deal with fluid energy markets. They add that changing customer habits takes time. They contend that the incremental efforts to date have borne fruit, as evidenced by the migration of 1 million customers (state-wide) to retail access service.

With respect to the Staff argument that adopting SCMC/RESA's hedging proposal would dilute the hedge's value and require more purchases to achieve the same pricing level, SCMC/RESA say it is unconvincing. SCMC/RESA assert that maintenance of a certain price range is a function of the actual movement in market prices and, thus, the number **[*116]** of hedges will depend on the movement in market prices. SCMC/RESA continue that since Staff cannot predict how prices may actually move, its argument against the SCMC/RESA proposal is speculative. SCMC/RESA add that on a total bill basis, their proposal would not impair rate stability or require the Company to purchase additional hedges to maintain the same level of overall rate stability. Finally, SCMC/RESA aver that, since ESCO customers help sustain and fund the Company through their delivery rates, it is entirely reasonable and equitable to flow the impact of hedging through the delivery component of rates. [154]

DISCUSSION

The Joint Proposal in these proceedings is the product of settlement negotiations that were noticed and executed in accordance with our settlement guidelines and rules of procedure. We therefore have evaluated it under our standards for

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[151] SCMC/RESA Post-hearing Memorandum at 4, citing Policy Statement at 40.

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[152] SCMC/RESA Post-hearing Memorandum at 5-7.

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[153] SCMC/RESA Post-hearing Memorandum at 7-9.

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[154] SCMC/RESA Post-hearing Memorandum at 9-11.

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reviewing joint proposals. [155] In general, a joint proposal is reviewed for determination that it achieves [*117] a reasonable balance among the protection of the ratepayers, fairness to investors, and the long term viability of the utility; consistency with sound environmental, social and economic policies; and results that are within the range of the likely results of a fully litigated proceeding. Moreover, in judging a joint proposal, the Commission gives weight to the fact that it reflects agreement among normally adversarial parties.

We have reviewed the terms of this Joint Proposal in the context of the parties' pre-filed testimony and exhibits, the public comments we have received, the parties' statements and post-hearing briefs, and the testimony and exhibits introduced at the evidentiary hearing held on May 4 and 5, 2006. Based on that review, we find that the terms of the Joint Proposal, as modified herein, will establish just and reasonable rates, terms and conditions and that approval, consistent with the discussion herein, is in the public interest.

We note that the [*118] Joint Proposal is endorsed by Central Hudson, Staff, Multiple Intervenors and DOD and is opposed by CPB, PULP, SCMC/RESA and Select Energy. CPB and PULP propose the addition and formulation of utility-provided fixed price options and they generally oppose the level of rate increases reflected in the Joint Proposal. Select Energy's and SCMC/RESA's opposition is limited, seeking, respectively, modification of certain gas balancing and hedging provisions. As such, we find that the Joint Proposal reflects a reasonable compromise among ordinarily adversarial parties representing a range of interests.

The willingness of disparate parties to endorse the Joint Proposal, particularly, where, as here, it calls for unavoidable rate increases, is a strong indicator that the resultant rate plan satisfactorily addresses a variety of interests. We note, in this regard, that CPB, though opposing the Joint Proposal as presented, acknowledges both the inevitability of rate increases in these proceedings and the fact that the proposal, as presented, contains positive elements. Moreover, we received extensive public criticism of the Company's initial proposed rate increases and our call for public comments [*119] on the Joint Proposal elicited similar comments. The bulk of the concerns expressed in the public comments, however, are addressed by the rate and service terms and conditions we are adopting, including, in particular, the enhanced low-income program and the phase-in and moderation of the proposed rate increases.

The overall electric and gas revenue increases of $ 53,033,000 million and $ 14,060,000 million, respectively, are well within the range of litigation outcomes in these proceedings. The revenue requirements were vigorously contested. Central Hudson initially proposed electric and gas revenue increases of approximately $ 72.1 million and $ 22.2 million, respectively, over a three-year period. Staff initially proposed a one-year plan with electric and gas revenue increases of approximately $ 40.4 million and $ 8.8 million, respectively.

Key elements in dispute included, not only the rate plan's term and the level of revenue increases, but also the allowed return on equity, future sales forecasts, depreciation expenses and reserve, rate design issues, the cost and timing of MGP/SIR expenditures, and the proper service quality targets. Moreover, significant disputes were not [*120] limited to the Company and Staff, but also included CPB, the Department of Defense and Multiple Intervenors. The dispute between the Company and the Department of Defense was very contentious and complex and concerned service to USMA and use of USMA's gas distribution system for service to Central Hudson's customers in Highland Falls. If left unresolved, it could have caused prolonged uncertainty and confusion regarding Central Hudson's rates and rate design.

In its Statement in Support of the Joint Proposal, Staff presents its view of the proposed electric and gas revenue increases. Staff has demonstrated to our satisfaction that the revenue requirement and rate increases are necessary and largely unavoidable. Staff highlights the fact that a significant portion of the proposed increases - 55% of the electric rate increase and 47% of the gas rate increase - are attributable to pension and OPEB expenses; [156] while another 20% of the electric increase and 8% of the gas increase are attributable to expenses that are necessary and, in some cases mandated, to ensure safety and system reliability. The presentations by Central Hudson, DOD and Multiple Intervenors further support our

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[155] 16 NYCRR 3.9; Opinion No. 92-2, *supra*.

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[156] Indeed, another 32% of the gas increase is due to the recovery of regulatory assets for gas, in part, attributable to prior pension and OPEB deferrals.

finding [*121] that the rate levels proposed under the Joint Proposal are reasonable and necessary and satisfy ratepayer and shareholder interests. The Company's endorsement of the Joint Proposal supports our finding that the revenue requirement is sufficient for Central Hudson to meet its obligations to the public to operate and maintain a safe and adequate system. As such, we find that the rate levels strike an appropriate balance between customer and Company interests.

A portion of electric depreciation reserve has been used to moderate the electric increases. Gas increases are mitigated by deferring and amortizing portions of the gas revenue increases. This addresses, to a degree, concerns regarding the impact of the rate increases on residential customers, particularly those on low and fixed incomes, and on schools and small businesses in the Central Hudson service territory. [*122] Those with the least ability to pay will benefit from the enhancement and expansion of the low-income program provided by the Joint Proposal. These elements of the proposal are recognized by opponents and proponents alike as positive elements.

The Joint Proposal's revenue allocation and rate design recommendations are consistent with our public policy objectives. Its allocation of the revenue requirement increase reflects a reasonable distribution of the increase across service classifications. The rate design reflects an appropriate balance among competing considerations, including, but not limited to, the avoidance of rate shocks, and furthering our policy for hedging electric commodity costs.

The new gas balancing program will provide daily balancing procedures for Central Hudson's largest customers and bring the Company's procedures into conformance with our recent balancing orders. With the implementation of the balancing and cashout provisions, imbalances will be properly priced, thus sending correct price signals to customers and enabling them to accurately arrange for commodity delivery. In addition, reliability should be enhanced as deviations between customers' proposed [*123] use and actual deliveries are minimized.

The resolution of the complex and contentious dispute between Central Hudson and the USMA ensures cost-based rates for service to the USMA and avoids the expense, time and uncertainty associated with the litigation that otherwise would have gone before the Armed Services Contract Board of Appeals. These uncontested provisions are clearly in the public interest.

The implementation of further rate unbundling will, in conformance with our Unbundling Policy Statement, replace the existing back-out credits with cost-based Merchant Function Charges. The Merchant Function Charges are priced at tiered levels to recognize the costs attributable to supplying commodity to a customer of an ESCO that participates in Central Hudson's Purchase of Receivables program and the costs for those ESCO customers who are outside the ambit of this program.

The portion of the rate increases related to maintaining system reliability and enhancing gas safety is necessary to ensure safe and adequate service. These allowances will be used to build a substation, expand electric transmission ROW maintenance efforts (in conformance with our orders) and replace gas cast iron [*124] and bare steel pipe. These improvements will enure directly to the benefit of all customers.

The expansion and enhancement of Central Hudson's low-income program addresses concerns regarding the rate increases' impact on low-income customers. The program carefully targets assistance to the customers who can benefit the most and tailors assistance to meet the needs of participating households. Program funding will increase from an initial level of $ 1.148 million in the first rate year to $ 1.5 million in third rate year. These uncontested provisions are in the public interest.

The Customer Service Quality Satisfaction and Gas Safety service metrics are reasonably designed and intended to encourage the Company to maintain and improve service, safety, and reliability. The Company has incentives to operate efficiently, while passing efficiency benefits along to ratepayers, through the earnings sharing provision.

As noted above, the contested elements of the Joint Proposal include the overall level of the rate increases, the absence of utility-sponsored fixed price offerings, and certain gas balancing and hedging provisions. We have carefully considered the merits of the opposition, as [*125] discussed in detail below. Our analysis leads us to reject most of the parties' proposed

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modifications.

CPB recommends that capital expenditures be reduced to the average of capital expenditures in the last four years adjusted for inflation. CPB also recommends that the Company file a deferral petition to recover any expenditures that exceed the amounts it advocates. Staff and the Company assert that the modification is unnecessary because the Joint Proposal requires the Company to defer, for ratepayer benefit, 150% of the return requirement equivalent of any shortfall in expenditures over the three-year rate term. They argue that this precludes the Company from seeking to improve its earnings by deferring capital expenditures. They add that the CPB's proposed modification ignores the fact that the increased funds are dedicated, in part, to constructing facilities needed to extend service to new customers and to make necessary gas infrastructure enhancements.

We recognize the importance of constraining rate increases, but all such efforts must be balanced against the equally important goal of ensuring safe and reliable service. Just and reasonable rates include, in this instance, **[*126]** ensuring that required utility infrastructure improvements are adequately funded. We therefore reject CPB's proposal. The shortfall mechanism goes a long way towards alleviating CPB's concerns as it ensures that the rate allowances approved here will either be spent for the designated purpose or be returned (150%) to ratepayers.

CPB recommends that the Joint Proposal be modified to reduce ROW maintenance amounts by $ 3 million per rate year, with any expenditures over the rate allowance recovered, if at all, by deferral petition. CPB also recommends the addition of shortfall protection with respect to the distribution ROW maintenance amounts.

Staff argues that a reduction is unjustified because CPB's calculation excludes expenditures funded through the Benefit Fund. The Company adds that CPB's calculation excludes tree-trimming costs. With respect to the deferral mechanism, Staff states that the extension of deferral incentive mechanisms to encompass this expense can have adverse consequences on the Company's incentive to control costs and pursue savings.

In light of CPB's acknowledgement of errors made in calculating its proposed reduction, the potential negative impacts associated **[*127]** with the reduction to and imposition of a deferral mechanism for these costs, and the importance of ensuring that funds for safe and reliable service are provided, the CPB's proposals to reduce distribution ROW maintenance amounts and implement a deferral mechanism are rejected.

With respect to application of a shortfall mechanism to distribution ROW costs, we do not find Staff's and Central Hudson's arguments persuasive. As CPB notes, distribution ROW maintenance expenditures account for the vast majority (about 78%) of total ROW maintenance expenditures. An incentive to encourage the Company to actually use the amounts as intended makes good sense and is consistent which the previously stated goal of ensuring a more reliable system. Further, we note that, when questioned, Staff conceded "there is no disadvantage" to subjecting the distribution ROW costs to the same true-up mechanism that applies to transmission ROW costs. [157] If the Company operates this routine portion of its business properly, the mechanism will not be triggered as the subject allowance will be fully expended. Under the circumstances presented here, adoption of the CPB-proposed shortfall mechanism provides protection **[*128]** for ratepayers and helps ensure reliability, without harming the Company. Accordingly, we require the rate allowances for distribution ROW costs to be subject to the same shortfall mechanism that applies to the transmission ROW costs.

CPB asserts that storm expense should be reduced by $ 2 million from the level reflected in the Joint Proposal. It claims that expected cost savings and additional revenue will result from a reduction in the number and duration of outages and these benefits will offset some costs. Staff asserts that CPB's analysis disregards the most recent data on storm costs. The Company characterizes the CPB's proposed adjustment as an attempt to cast aside proven methodology and claims that CPB's testimony actually confirms the expense levels are correct. We find that the record supports a level of storm expense that is reasonably based on the four-year average of historical expenditures, adjusted for inflation. Consequently, we are not adopting the CPB proposal.

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[157] Tr. 1601.

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CPB recommends that [*129] the Company be required to absorb 10% of MGP/SIR costs. Staff and the Company counter that the CPB recommendation is based on outmoded precedent and does not favor a clean environment. We consider the full recovery of MGP/SIR costs to be a reasonable utility expense. Accordingly, we reject the proposed modification.

We note that these proceedings are the first to address and incorporate the deferred and projected MGP/SIR costs into a rate plan. The Joint Proposal provides that the carrying charges applicable to MGP/SIR deferrals should be changed from the unadjusted customer deposit rate, currently 4.75%, to a return that equals Central Hudson's pre-tax rate return, 10.01%. [158] CPB opposes this provision. We, however, approve this proposed change based on our finding that it properly recognizes the long-term nature of the MGP/SIR Program and the difficulty of including current funding in the proposed rates. We note the our approval ensures compensation for Central Hudson at its overall cost of capital for cash expenditures that require financing, without increasing proposed rates.

[*130]

CPB urges us to change the pension and OPEBs discount rate to 5.75%, which it states is supported by recalculating the rate using the most recent data available. CPB also recommends that the Joint Proposal be modified to capture any savings that might result if the Company changes its defined benefit pension plan during the three-year rate term. CPB further recommends extending the deferral period for pension plan losses by an additional ten years. Staff asserts a discount rate update now would be immaterial and superfluous and we agree. We also share Staff's concern that extending the length of the deferral period would conflict with the requirements of the Pension and OPEB Statement and Order. Finally, we are also persuaded by arguments that there is no reason or need at this time to attempt to prematurely capture savings that have not even been estimated. We therefore decline to adopt CPB's proposed modifications to pensions and OPEBs.

CPB asserts that Central Hudson's cost of equity should be reduced from 9.6% to 8.95%. Staff and the Company assert that the proposed 9.6% ROE is fully justified. Central Hudson further asserts that CPB's efforts to decrease an already low ROE are [*131] unreasonable and misapplies the Generic Finance Case's guidance. The method employed to set the allowed equity return is within the range of reasonable results that can be adopted here. In declining to modify the proposed 9.6% equity return allowance, we recognize that this item is but one many elements and interrelated provisions, including the associated but uncontested earnings sharing mechanism and the limitation of certain deferrals. We decline to upset the reasonable balance that has been established with respect to these provisions.

We also find that CPB's recommendations against an AMR pilot or a metering study are premature. The Joint Proposal clearly provides that the pilot and the study will be developed by the Company and filed for our approval. They will only proceed if we approve them. Thus, CPB can pursue its objections to such plans when they are filed. In addition, CPB's request to use funds dedicated to the proposed pilot and study to further mitigate rates is likewise rejected because (1) no rate allowances have yet been committed to either of these proposals and (2) CPB has not persuaded us that a change to our prior orders is warranted.

CPB opposes the reversal [*132] of the 2005 reliability penalty. The Company asserts that CPB's position fails to recognize the provision in context with other, interrelated provisions. Staff contends that CPB's opposition ignores the fact that prior rate orders specifically authorize excuse of a failure that is shown to be caused by the OMS introduction. For the reasons provided by Staff and the Company, we reject CPB's recommendation. We find that a reasonable compromise was made on this item in the context of the many other related provisions. Also, given the uncertainty attending this contested issue, the provision represents a reasonable compromise and should not be disturbed.

CPB recommends that funds remaining in the electric depreciation reserve account be used to further moderate the proposed rate increases. Staff argues that CPB's presumption as to amount of mitigation that could be funded in this manner is incorrect. The Company asserts, *inter alia*, that CPB's proposal ignores the nature of the assessment of excess reserve. Given the difficulties associated with forecasting certain types of large, future deferrals and our policies favoring rate

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[158] Central Hudson currently has authorization to defer MGP/SIR related expenditures and to accrue carrying charges on the deferred balance at a rate equal to the unadjusted customer deposit rate.

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stability, we are not persuaded that the several disadvantages [*133] attending the complete depletion of excess depreciation reserve outweigh the one and only identified (and purportedly minimal) benefit. We therefore reject CPB's proposal.

CPB and PULP oppose the level of expenditures for retail access programs and seek reassignment of a portion of such amounts to outreach and education for purposes other than retail competition. Central Hudson claims that CPB's and PULP's challenges and proposed modifications lack justification and evidentiary support, and are inconsistent with Commission policy. The Company adds that any legitimate concern regarding the level of such expenditures is addressed by the deferral mechanisms. Staff asserts that Central Hudson has only made expenditures that are in conformance with the 2004 Rate Plan Order or that are needed to implement the programs called for in the Retail Access Order. SCMC/RESA claim that proposals to reduce such expenditures are short-sighted and should not be adopted. We are persuaded by the proponents' and SCMC/RESA's arguments that the funding for retail access programs is proper and conforms to and furthers our orders and policies favoring of development of the competitive market.

The offering [*134] of utility-sponsored fixed price options engendered significant controversy in these proceedings. The first question presented is whether utility-sponsored fixed price options can be raised and considered in these proceedings. We are persuaded, mainly by the arguments in CPB's post-hearing brief, that there is no bar to CPB and PULP presenting their proposal in these proceedings. However, as the proponents of utility fixed price options, they must demonstrate sufficient justification for their adoption. [159]

CPB and PULP claim that consumers have a strong preference for fixed price energy products from the utility. They state that consumers without substantial financial assets decrease spending on items, such as food, to cover unanticipated increases in their home energy bill. They assert that the availability [*135] of reasonably priced fixed price products would help them avoid such dilemmas. They also argue that ESCOs are not offering fixed price electricity or gas products at reasonable prices nor have the number of such providers increased as seemed to be expected in the July 2005 Order.

CPB and PULP also claim to have demonstrated that reinstitution of utility-provided fixed price options is consistent with Commission orders on retail competition because the competitive market has not responded adequately and because Central Hudson can be distinguished from other utilities that do not offer fixed price options.

On the other hand, Central Hudson, Staff and SCMC/RESA argue that reinstituting utility fixed price offers would do little to remedy the impact of commodity price increases but would cause long-term harm to low-income customers, in particular. They argue it would also distort and retard the development of retail market to the disadvantage of consumers, and not yield better prices for consumers.

We agree with Staff that the design that has been suggested for the proposed utility fixed price options lacks sufficient detail to be implemented successfully, and we note that there is insufficient [*136] time to remedy such deficiencies and implement utility sponsored fixed price options in time for the 2006-2007 heating season. [160] However, even if these deficiencies could be remedied, we are not convinced that utility-provided fixed price options should be required in these proceedings. We note, in particular, the CPB's testimony that its main intent in proposing the options is to ″provide customers a tool for dealing with price volatility.″ [161] We further note CPB's recognition of the fact that ″there's no

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[159] In its post-hearing brief (at 8) CPB notes that it ″may face a difficult burden in overcoming recent precedent set by the Commission's decision in the gas FPO case, but it is not precluded from making the effort.″

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[160] CPB acknowledges that, normally, a fixed price offer involves the announcement of such an offer and receipt of responses, which in turn permit determination of the required volume of hedging instruments and fixed price purchases. In addition, CPB indicates that cost issues - both as to the price to be set for the option and the method of recovering any differences between estimates and actuals, are not addressed by its proposal at this time but are implementation issues that should be addressed by the Commission. Given that the 2006-2007 heating season starts October 1, there would be insufficient time to properly conduct these necessary steps. Tr. 914-918.

[161] Tr. 919.

guarantee that fixed price option[s] will be better for customers than a variable price." [162] Budget or levelized payment plans are available, as required by law, [163] to all utility customers, and they already provide a tool by which customers can achieve certainty with respect to their monthly bills. Moreover, the record shows there is a competitive market in Central Hudson's territory, which includes provision of fixed-price offers from competitive suppliers. Our consideration of these factors, and of the concerns that were raised by Staff, the Company and SCMC/RESA, result in our conclusion that the addition of utility-provided fixed price options need not be required **[*137]** here.

As discussed in more detail above, Select Energy opposes the Joint Proposal's provisions on balancing, cash-out and delivery proposals for service classifications 6, 12, and 13. Its suggested modifications are opposed by Multiple Intervenors, the Company and Staff. We are persuaded **[*138]** by proponents' arguments that Select Energy's position should be rejected.

SCMC/RESA allege that the proposed hedging provision is at odds with Commission policy, acts to hinder competition and is inherently illogical. SCMC/RESA argue that until the Commission determines that residential and small commercial classes have available equivalent hedge products, it must ensure that the utility hedging activity reflected in rates is consistent with the utility's regulated monopoly advantages and is equitable to ESCOs and retail access customers. Staff asserts that SCMC/RESA's position contravenes Commission policy and would dilute the value of the hedge. Staff states that the proposal as it currently stands allows customers to accurately compare utility commodity offerings to ESCO offerings. Parties on both sides of the issue raise policy matters that merit further and more in-depth consideration. As these issues also may be of state-wide relevance, they should be further explored and considered in a new generic proceeding. Depending on the outcome of that generic proceeding, its results could be incorporated into later years of this multi-year rate plan, or deferred to the next rate proceeding. **[*139]** We will review what, if anything, needs to be done for this rate plan at the conclusion of the generic proceeding, after the views of the parties are solicited. However, the treatment set forth in the Joint Proposal, which continues the existing Company practice, will be adopted for now.

We expressly note that our approval of the rate plan does not affect our reserved authority to require a change in base rates, should we find that, because of unforeseen circumstances, Central Hudson's actual return in any annual period during the rate term is unreasonable or insufficient to support safe and adequate service at just and reasonable rates.

In sum, we conclude that the rate plan established here will provide just and reasonable rates, terms and conditions and that approval, consistent with the discussion herein, is in the public interest.

<u>The Commission orders</u>:

1. The rates, terms, conditions, and provisions of the Joint Proposal dated April 17, 2006 (Restated April 19, 2006), filed in this proceeding and attached hereto as Attachment 1, are adopted and incorporated herein to the extent consistent with the discussion in this Order.

2. Central Hudson Gas & Electric Corporation shall **[*140]** file a written statement of unconditional acceptance of this Order, as of the date of the tariff filing required by ordering clause number three below.

3. Central Hudson Gas & Electric Corporation is directed to file a supplement, on not less than one day's notice, to be effective on July 31, 2006, to cancel the tariff leaves and supplements listed in Attachment 2.

4. Central Hudson Gas & Electric Corporation is directed to file, on not less than one day's notice, to take effect on August 1, 2006 on a temporary basis, [164] such tariff amendments [165] as are necessary to effectuate the terms of this Order. Upon filing these tariff amendments, Central Hudson Gas & Electric Corporation shall serve copies on all active parties to this

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162 <u>Id.</u>

163 Public Service Law § 38.

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164 Given the tariffs' August 1, 2006 effective date, the make whole approved in this Order applies to the month of July 2006.

proceeding. Any party wishing to comment on the tariff amendments may do so by filing an original and five copies of its comments with the Secretary and serving its comments upon all active parties within ten days of service of the tariff amendments. The amendments specified in the 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 [*141] not in compliance with this Order.

5. The requirement of the Public Service Law Section 66(12)(b) that newspaper publication be completed prior to the effective date of the amendments is waived; provided, however, that Central Hudson Gas & Electric Corporation shall file with the Secretary, no later than six weeks following the effective date of the amendments, proof that a notice to the public of the changes set forth in the amendments and their effective date has been published once a week for four consecutive weeks in one or more newspapers having general circulation in the service territory of the Company.

6. Upon acceptance by Central Hudson Gas & Electric Corporation of [*142] this Order, the Company shall withdraw its pending petition in Case 04-G-0463 for rehearing concerning gas balancing.

7. Upon acceptance by Central Hudson Gas & Electric Corporation of this Order, the Company shall withdraw its pending petition in Case 00-E-1273 for rehearing of the Commission's Order issued September 30, 2005 concerning electric reliability.

8. These proceedings are continued.

By the Commission

ATTACHMENT 1

JOINT PROPOSAL

APRIL 17, 2006

(Restated April 19, 2006)

<u>APPENDICES</u>

Appendix A: Electric Income Statements (for twelve month periods Ending June 30, 2007, 2008 and 2009)

Appendix B: Electric Customer Class Rates of Return Appendix C: Table of Electric Delivery Rates Including MFCs

Appendix D: Gas Income Statements (for twelve month periods Ending June 30, 2007, 2008 and 2009)

Appendix E: Gas Embedded Cost of Service Summary (for twelve month period Ending June 30, 2007)

Appendix F: Table of Gas Delivery Rates Including MFCs

Appendix G: Deferred Electric and Gas Items for Offset

Appendix H: Capital Structure and Allowed Rate of Return

Appendix I: Certain Deferred Items Subject to Limitation

Appendix J: Electric, Gas and Common Depreciation
[*143]

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[165] The tariff amendments that are required to effectuate this Order's gas balancing requirements should be filed on March 1, 2007 and March 1, 2008, to take effect April 1, 2007 and April 1, 2008 respectively.

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Appendix K: Gas Balancing Methodology Applicable to SC 9 &11.

Appendix L: Detailed CSI Margin of Error Calculation

JOINT PROPOSAL

(April 17, 2006; Restated April 19, 2006)

I. PROCEDURAL BACKGROUND

On July 29, 2005, Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company") filed amendments to its tariff schedules, P.S.C. No. 15 - Electricity, and P.S.C. No. 12 - Gas. By Order issued August 24, 2005, the Commission initiated the above-captioned proceedings and suspended the operation of the tariff amendments until December 26, 2005. The suspension period was later extended to June 26, 2006. In addition, Central Hudson proposed a one month extension by letter to the Secretary and an additional one month extension on the record of a Pre-Hearing Conference held on March 9, 2006; both extensions subject to make whole provisions.

On September 30, 2005, the Presiding Administrative Law Judges ("ALJs") issued a Ruling establishing the procedural schedule. In accordance with the procedural schedule, Department of Public Service Staff ("Staff") and Intervenor direct testimony was filed on November 21, 2005, and rebuttal testimony was duly filed on December 14, [*144] 2005. The supplemental testimony of Company witness Paul Haering was filed on November 19, 2005, and the Department of Defense (DOD), on behalf of the United States Military Academy at West Point ("USMA" or "West Point") filed the initial testimony of Kenneth Kincel on December 19, 2005. Furthermore, the ALJs' Second Procedural Ruling in these proceedings, issued November 5, 2005, determined that monthly gas balancing issues would be heard in these proceedings and the Commission's Order of November 29, 2005 required that Central Hudson make a filing addressing daily gas balancing in these proceedings. Supplemental testimony of Company witness Glynis Bunt was duly filed on January 4, 2006 in response to those requirements.

By Ruling issued January 13, 2006, the ALJs cancelled the hearings scheduled for January 18, 2006, upon consideration of a telephone request by several parties seeking additional time to negotiate the development of a Joint Proposal. The procedural schedule was revised by the ALJs in a Ruling issued January 17, 2006, granting a request for a postponement and extension of the procedural schedule for the purpose of accommodating the progression of good faith settlement [*145] negotiations. This Ruling established the target date of February 28, 2006 for the parties to submit a Joint Proposal together with an Executive Summary.

Settlement discussions were conducted on January 12, 2006, in response to a Notice of Impending Negotiations dated January 6, 2006 filed by the Company. Additional negotiating sessions were conducted upon prior notice to all participating parties on January 18, 19, 24, and 31, February 3, 7, 14, and 17. On March 9, a Settlement Judge, Jeffrey Stockholm, was appointed and conducted mediation of the negotiations commencing on March 10, 2006. Further negotiating sessions were held on March 10, 17, 23, 27, 28, and 30, and April 4, 6, 11, 14, and 17, 2006. On April 3, 2006 a revised schedule was established by the ALJs, calling for the submission of the Joint Proposal on April 17, submission of statements in support or opposition and any evidentiary presentations by parties opposing the Joint Proposal on May 1, 2006, commencement of hearings on May 4, 2006 and submission of briefs (limited to thirty pages) on May 12, 2006.

As a result of the extensive settlement processes, the parties listed at the end hereof have reached the agreements [*146] on the outcome of these proceedings reflected in this Joint Proposal, and they recommend to the Commission that it approve this Joint Proposal.

II. TERM

This Joint Proposal is for a three-year electric and gas rate plan, commencing July 1, 2006 and continuing through June 30, 2009 (see also Section XVIII.H). "Rate Year" ("RY") means a 12-month period starting July 1 and ending on the following June 30. RY1 is the twelve months ending June 30, 2007; RY2 is the twelve months ending June 30, 2008 and RY3 is the twelve months ending June 30, 2009.

III. ELECTRIC RATES

A. Electric Delivery Revenue Requirements.

1. The electric delivery revenue requirements shown in Column A, B, and C, Line 2 of Appendix A, Schedule 1, are prior to rate moderation.

2. Electric delivery revenue requirements have been moderated through use of a portion of electric depreciation reserve that is in excess of the theoretical book reserve, to offset and ″shape″ the revenue requirement increases, so as to produce three approximately equal increases in revenue requirement over the three rate years. The revenue requirements have been moderated as shown Appendix A, Schedule 2.

3. The Income [*147] Statements for Electric Delivery Service set forth in Appendix A show that this Joint Proposal is reasonable.

B. Electric Revenue Allocation.

For all rate years, the electric revenue allocation among service classifications (SC) is subject to constraints of a minimum increase of 0.75x system average, and a maximum increase of 1.25x system average, with the exception of SC 9. For SC 9, a constraint of 0.50x system average has been applied and a specific allocation of an additional $ 50,000 of annual revenue requirement responsibility to SC 9 has also been made. The resulting percentage changes by class for each rate year are summarized in Appendix B.

C. Electric Rate Design

1. Class billing determinants are shown in Appendix C.

2. Central Hudson's electric rates had previously been separated into delivery and commodity components. As discussed in Section VI below, the electric delivery rates developed in this Joint Proposal reflect further unbundling, through transferring additional commodity-related costs to new Merchant Function Charges (″MFCs″) also discussed in Section VI.

3. Beginning on July 1, 2006 (RY1), the rate design for SC 3 and 13 will be changed [*148] to a two-part (customer charge and demand charge) rate design, exclusive of MFCs.

4. The electric delivery rates (including MFCs) are set forth in Appendix C.

D. Electric Commodity .

1. The existing Energy Cost Adjustment Mechanism (″ECAM″) mechanisms being used to recover the costs of electric commodity from Central Hudson customers will continue, subject to the modifications described below.

2. The existing hedges (known as Constellation and Entergy) will be maintained in the Purchased Power Adjustment (″PPA″) and Market Price Charge (″MPC″) mechanisms, respectively, in accordance with current practices.

a) Hedges entered into post-June 30, 2006 will be reflected in MPCs for residential and small commercial customer classes.

b) There will be no new hedges for SC 3 or 13, which are real time pricing classes.

c) Nothing in this Joint Proposal is intended to alter the pre-existing treatment of legacy hedges established in the existing Commission-approved rate plan.

3. Three MPC Groups will be implemented on July 1, 2006.

a) The separate MPCs are: 1) for SC 1, 2 and 9; 2) for SC 6 (residential time-of-use); and 3) for SC 5 and 8.

b) MPCs will be based [*149] on each group's average load shapes.

c) Effective July 1, 2007, the SC 6 MPC shall be differentiated into on-peak and off-peak rates, with the same on-peak rate applied to all SC 6 on-peak rate periods and the same off-peak rate applied to all SC 6 off-peak periods.

d) Recovery of NYISO Ancillary Services Charges and NYPA Transmission Access Charges ("NTAC") will be moved from the Miscellaneous Charges Factor of the ECAM into the MPCs and Hourly Pricing Programs as of July 1, 2007.

e) As of July 1, 2007, the Company will cease reimbursing Energy Service Company (ESCO) retail commodity suppliers for ancillary service costs and NTAC.

f) Commodity-related uncollectibles and working capital costs shall continue to be recovered through commodity charges. There are no net lost revenues associated with the uncollectibles or working capital costs.

IV. GAS RATES

A. Gas Delivery Revenue Requirements.

1. The gas delivery revenue requirements, as shown in Columns A, B and C, Line 2 of Appendix D reflect rate moderation achieved through deferring a portion of the RY1 increase and amortizing it, along with revenue requirement increases in RY2 and 3, in an amortization commencing [*150] in RY2. This approach also permits a zero rate increase in RY3. The amortization of the gas net regulatory assets is addressed in more detail in Section X.B.2 and .3.

2. The Income Statements for Gas Delivery Service set forth in Appendix D show that this Joint Proposal is reasonable.

3. The Gas Income Statements include an interruptible profit imputation of $ 1.0 million each rate year. Because of the imputation, the Company is permitted to retain the first $ 1.0 million in revenues in each rate year that it may receive from interruptible service and service to electric generators, subject to the following.

a) If the margin does not reach $ 1.0 million in any rate year, the Company is authorized to surcharge ratepayers for 100% of the first $ 0.25 million of the shortfall and 90% of the remaining shortfall.

b) If the margin exceeds $ 1.0 million in any rate year, the Company will credit ratepayers for 100% of the first $ 0.25 million of the excess and 90% of the remaining excess.

4. Central Hudson's gas rates had previously been separated into delivery and commodity components. As discussed in Section VI below, the gas delivery rates developed in this Joint Proposal [*151] reflect the transfer of additional commodity-related costs to new MFCs.

B. Gas Cost of Service and Rate Design.

1. Gas rates have been developed using the Embedded Cost of Service Study summarized as Appendix E.

2. Revenue Allocation. Class billing determinants and the resulting rates, including MFCs, are shown in Appendix F.

3. For residential gas customers, the minimum charge will be increased to $ 14 per month, and the volumetric delivery rates for the penultimate block and tail block will be set at a ratio of 1.6:1, respectively.

C. SC-11 Distribution Large Mains Classification

1. A new SC-11 subclass, ″Distribution Large Mains″ (″SC11DLM″)″ will be established as of July 1, 2006.

a) The new SC11DLM subclass will be applicable to customers using over 400,000 Mcf/year, taking service from Company facilities below transmission pressures and from mains at least 6″ in diameter.

b) The rules and regulations of SC-11 apply to SC11DLM.

c) The costs allocated to SC11DLM are shown on Appendix E, subject to the following:

(1) The costs of mains below 6-inch in diameter are excluded.

(2) The operating expenses resulting from Central Hudson payments to [*152] USMA are included in FERC/PSC Account 860 and are allocated to all classes of service other than SC11DLM.

(3) All other cost of service treatments applied to SC-11 D are also applied to DLM.

(4) The system average rate of return is used to develop the revenue requirement for SC11DLM.

d) SC11DLM rate design follows SC11 D and is based on Maximum Daily Quantity (″MDQ″). RY1 through RY3 rates for SC11DLM are shown on Appendix F.

e) The SC11DLM MDQ that is in effect for a customer may be revised downwards for permanent reductions to the gas load on the customer's premises caused by installations of, or modifications to, gas equipment, including the possible installation of a propane-air facility. The amount of such downward adjustment to the MDQ will be reasonably determined based on engineering studies prepared by the Customer and furnished to the Company and Staff, on the effect of the gas equipment changes.

(1) The downward adjustment to the MDQ shall be effective during the first month for which the changes in gas equipment are placed in service.

(2) Any customer proposing to reduce its MDQ based on a propane-air facility will provide Staff and the Company written notice [*153] at least six months in advance of the date on which the proposed changes in gas equipment will be placed in service.

(3) In the event of reductions in MDQ based on customer conservation measures, the Company will be permitted to defer the lost revenues for future recovery, with carrying charges at the pre-tax authorized rate of return.

2. Treatment of USMA.

a) Central Hudson will install demand meters at Hotel Thayer and at the Village of Highland Falls by November 1, 2006.

b) USMA will be provided service after June 30, 2006 in accordance with the provisions of the SC11DLM class, and after execution of a contract within 10 days of a Commission decision on this Joint Proposal between Central Hudson and the Department of the Army on behalf of USMA, incorporating the provisions set forth below and filed with the Commission. The contract (Modification P00050) will be a further modification of the current Contract DAAG60-91-C-0087 as modified through Modification P00049. Modification P00050 will not contain the rates referenced in Modification 49. Modification 50 shall include all FAR clauses that were incorporated into the contract by Modification P00049 (effective September [*154] 1, 2005) except for FAR 52.241-8 (which shall be replaced by FAR 52.241-7, Change in Rates or Terms and Conditions of Service for Regulated Services (Feb 1995)) and the FAR clause incorporated at Paragraph 10 of Modification P00049 (entitled ″Requirement for Certificate of Procurement Integrity (Nov 1990).″

c) The contract modification will:

(1) Provide for firm transportation service in accordance with all provisions of SC11DLM.

(2) Incorporate the rules and regulations of SC11DLM, including balancing.

(3) Specify that the Standard SC11DLM tariff rules for adjusting MDQ identified above will apply to USMA and that the current USMA MDQ is 5833 mcf.

d) The contract modification will address the use of the USMA system to deliver gas to Central Hudson's customers in the Village of Highland Falls and to the Hotel Thayer as follows.

(1) Central Hudson shall credit to USMA $ 5.53 per Mcf of MDQ for deliveries to Highland Falls and Hotel Thayer during each month of RY1 through RY3.

(2) The initial MDQ for Hotel Thayer shall be 27 Mcf. The initial MDQ for Highland Falls shall be 904 Mcf.

(3) The MDQ for any given month shall be the highest daily volume delivered during [*155] the current month or the preceding 11 billing months.

(4) A loss factor of 2.564% shall be applied to the volume of gas delivered to Highland Falls and Hotel Thayer times the unit cost of the gas commodity to USMA for the corresponding month. USMA will provide Central Hudson with copies of invoices to establish the monthly USMA unit cost of gas commodity.

e) The contract shall provide that, for the term of the contract, Central Hudson will, subject to the provisions of leaves 65 and 66 of its gas tariff (PSC No. 12), deliver up to 500 Mcf per hour (relating to capacity, not MDQ) at 90 psig or greater at Crow's Nest at no additional charge to USMA and at no premium upon the rates specified in Appendix F. In addition, the contract will further provide that, for the term of the contract, USMA will maintain 30 psig at Thayer Gate provided that the pressure at Crow's Nest is 90 psig or higher, and the flow of gas to the Village of Highland Falls and the Hotel Thayer does not exceed 50 Mcf per hour.

f) The contract Term shall be for a fixed term ending June 30, 2009.

D. Gas Commodity .

1. The existing mechanisms and practices under the Gas Supply Charge (GSC), Firm Transportation [*156] Rate (FTR), Interruptible Transportation Rate (ITR) and Interruptible Gas Rate (IGR) that are related to recovery of costs incurred in supplying gas commodity will continue, subject to the modifications described in Sections V and VI below.

2. Commodity-related uncollectibles and working capital costs shall continue to be recovered through commodity charges. There are no net lost revenues associated with the uncollectibles or working capital costs.

V. GAS BALANCING

A. General.

1. The new gas balancing approach described below will become effective as of April 1, 2007 for interruptible and firm transportation classes (SC-9 and 11, respectively), and for the aggregated transport classes (SC-6, 12, and 13). Applicable portions of the procedures described in the Company's July 29, 20005 ″Report on Gas Balancing and Cashout Issues″ will be followed in implementing balancing.

2. Incremental software costs for monthly and daily balancing will receive deferral accounting, for later recovery including carrying charges at the pre-tax authorized rate of return.

B. S.C. 9 and 11.

1. A separate volumetric Balancing Service Charge will be implemented as follows:

[*157]

a) There will be two separate rates: one for daily balanced customers and one for monthly balanced customers.

b) The methodology for calculating monthly and daily balancing service charges is shown in Appendix K.

c) The charges will be updated at least annually, to be effective April 1 of each year, using the methodology shown in Appendix K. The updates will be based on each service classification's total consumption and deliveries during the preceding winter period and the Company's then most recently available gas storage and other relevant costs. At least 30 days prior to the effective date of an update, the Company will file a statement of Gas Balancing Rates.

d) Transition. The charges shown below have been developed using the methodology depicted in Appendix K, based on currently available information. These charges are scheduled to be updated as of April 1, 2007, except for SC 11DLM. The rates set forth below will remain in effect for SC 11DLM customers until March 31, 2008.

	Monthly $/Mcf	**Daily $/Mcf**
SC-9	$ 0.0791	$ 0.0112
SC-11	0.0463	0.0164
SC11DLM	0.0463	0.0164

e) Effective April 1, 2008, the charges for SC 11 and SC 11DLM will be [*158] determined separately, based on the specific peak day history for each class.

2. Customers will be allowed to designate an ESCO retail supplier to be responsible for supply nominations and to effectuate the exchange of any imbalances hereunder with similarly situated customers.

3. Commencing April 1, 2007, Balancing Service Charges will be billed to the customer, and imbalance penalties will be billed to the customer's ESCO. Customers will be obligated to require their ESCOs to enter into an agreement with Central Hudson to pay for such penalties. Prior to April 1, 2007, all charges will continue to be billed to customers.

4. Balancing Service Charge revenues will be credited to the Gas Supply Charge.

5. Customers served under negotiated contracts will be rolled into the provisions applicable to similarly situated tariff customers upon the conclusion of contract negotiations or renegotiations.

6. The term of the balancing option period will be modified to provide customers with a semi-annual election of daily or monthly balancing for the periods November 1 - April 30 and May 1 - October 31.

a) An existing customer will be required to notify the Company of its selected [*159] balancing option for an applicable period on or before the date published in the Company's Calendar of Gas Transportation Schedule (column 4 - deadline for interruptible transport enrollment).

b) A customer taking service under SC 9 will maintain its balancing option for the full balancing period regardless of whether the customer switches to service under another service classification or to its alternate fuel and subsequently returns to SC 9 service.

c) Absent timely receipt by the Company, of notification from the customer electing its balancing option, the customer will placed in monthly balancing by default.

7. The following daily balancing provisions in the current tariff will be eliminated:

a) If on any day a customer's over-delivery or under-delivery is less than 10% of a customer's actual daily usage, the customer may adjust subsequent daily deliveries to the Company by an amount not to exceed 10% of any day's usage to eliminate any over-or under-deliveries by the end of the month.

b) If on any day a customer's cumulative over-delivery exceeds 125% of the customer's maximum daily quantity (MDQ), the cumulative over-delivered volume in excess of 125% of the MDQ [*160] will be purchased by the Company at a rate equal to 90% of the daily Index Price for that day.

c) If on any day a customer's cumulative under-delivery exceeds 125% of the customer's MDQ, the cumulative under-delivered volume in excess of 125% of the MDQ will be sold to the customer by the Company at a rate equal to 110% of the daily Index Price for that day.

8. For daily balanced customers, daily over-or under-deliveries will be ″cashed-out″ according to the existing tiering and pricing structure contained in the Company's tariff only when the combined over-or under-delivery for the ″pool″ of SC 9 and SC 11 daily balanced customers is greater than 10%.

9. The month-end cashout provisions for both daily and monthly balanced customers will allow customers that have cumulative over-or under-deliveries (″imbalances″) at the end of the month to exchange the imbalance with another SC 9 or SC 11 customer. Such exchanges of imbalances will be accomplished upon notification to the Company of the exchange by the applicable customer, or its designated supplier, prior to the imbalance resolution due date, which is five business days after the applicable month end. The imbalance resolution [*161] due date will be added to the Company's Calendar of Gas Transportation Schedule. The net effect of all imbalance exchanges must improve a customer's relative imbalance position. In no event will the Company process exchanges that result in a larger negative position for the customer.

10. The cash out will be according to the following revised tiering and pricing applicable to SC 9 and SC 11 daily balanced customers:

November - March	**Over - Deliveries**	**Under - Deliveries**
0% to 5%	Index	Index
5% to 10%	90% of Index	110% of Index
> 10%	80% of Index	120% of Index
All Other Months	**Over- Deliveries**	**Under- Deliveries**
0% to 10%	Index	Index
> 10%	80% of Index	120% of Index

The over-delivery Index Price will be equal to the average of the daily averages of the ″Midpoint″ rates for ″Tennessee, zone 0″ and Tennessee, zone 1″ (500 and 800 legs) receipt points as published in Platt's gas Daily in the table ″Daily Price Survey″ for the applicable month, plus the Company's weighted average cost of transportation and fuel losses.

The under-delivery Index Price will be equal to the average of the ″Midpoint″ rates of the higher of ″Transco, zone 6 N.Y.″ and ″Iroquois, [*162] zone 2″ receipt points as published in Platt's Gas Daily in the table ″Daily Price Survey″ under the Citygates heading for the applicable month.

11. The month-end cashout provisions applicable to the resolution of over-and under-deliveries for SC 9 and SC 11 monthly balanced customers will be revised to correspond to the month-end cashout provisions applicable to SC 9 and SC 11 daily balanced customers:

a) Over-deliveries will be purchased according to the tiering and pricing structure applicable to month-end cashouts for daily metered customers. As a result, the SC 11 ″banking″ provision will be eliminated and Company purchases will be priced at the same rate regardless of service class, and will be based on a published index.

b) Under-deliveries will be purchased according to the tiering and pricing structure applicable to month-end cashouts for daily metered customers. As a result, Company sales will be priced at the same rate regardless of service class, and will be based on a published index.

12. At such time as Central Hudson issues an Operational Flow Order (″OFO″) to safeguard the operational integrity of

its system:

a) Gas delivered to Central Hudson's system, [*163] less any LAUF adjustment, for a daily balanced customer will be required to be within two percent (2%) of the customer's daily usage;

b) The daily cashout tiering provisions of SC 9 and SC 11 will be revised such that the first tier will apply to daily over-and under-deliveries greater than 2% up to and including 15%.

c) These requirements will remain in effect for the duration of the OFO.

13. Upon the Commission's adoption of this Joint Proposal, the Company will request the Commission's permission to withdraw the Company's pending petition in Case 04-G-0463 for rehearing concerning gas balancing.

C. S.C. 6, 12 and 13.

1. Reconciliations and true-ups will be performed semi-annually; once for the 5 months ending March 31, and once for the seven months ending October 31.

2. Effective 4/1/07, ESCO retail suppliers will be allowed to trade offsetting monthly imbalances as part of the semi-annual reconciliation/true-up.

3. During the summer months, CHG&E will use the monthly average of the daily average of the ″midpoint″ rates for the Tennessee zone 0 and Tennessee zone 1 (500 and 800 legs) receipt points, plus the company's weighted average cost of transportation [*164] and fuel losses, as the cashout price for both under-deliveries and over-deliveries.

4. The pricing for Winter Bundled Sales Service (WBS) gas would be based upon: Inside FERC Gas Market Report - First of Month Index for each month between April - October for the following trading points; 50% ″Dawn Ontario″ & 50% ″TCPL Alberta, AECO″ to produce a ″blended index″ for each month.

a) Individual months would be weighted by adding the following monthly values and dividing the total by six:

April Blended Index divided by two
May Blended Index
June Blended Index
July Blended Index
August Blended Index
September Blended Index
October Blended Index divided by two

b) The above commodity cost would then be adjusted to include storage charges, firm transportation charges, including fuel, from market area storage to the Company's city gates, and carrying charges on the cost of gas in storage.

VI. RATE UNBUNDLING

A. Electric Unbundled Rates and Backout Credits.

1. The back out credits and related treatment contained in the Commission's October 25, 2001 Rate Plan (Sections IX.D and X.D.1) in Cases 00-E-1273 and 00-G-1274, and its June 14, 2004 Rate Plan in those proceedings [*165] will be maintained through June 30, 2007, except that the cost of the electric backout credits will be charged against the excess electric depreciation reserve.

2. At July 1, 2007, the electric backout credits will be replaced by four electric MFC groups, and the lost revenue provisions described below.

3. The four electric MFC groups are 1) MFC 1 for SC 1 and 6, 2) MFC 2 for SC 2, 3) MFC 3 for SC 3 and 13, and 4) MFC 4 for SC 5, 8, and 9. The new MFCs include cost-based components to represent commodity-related purchasing, credit and collection, call center costs, advertising and promotions, and related Administrative and General (A&G) expenses and rate base items allocated to each group.

B. Gas Unbundled Rates and Backout Credits.

1. From July 1, 2006 through June 30, 2007, the existing backout credits will continue to apply and will continue to be recovered through the Gas Supply Charge.

2. Gas delivery service MFCs, analogous to those described above for electric delivery service, will be implemented on July 1, 2007. The two gas MFCs are MFC 1 for SC 1 and MFC 2 for SC 2.

C. Two Tier MFCs.

Each MFC group will be further sub-divided into an MFC[A] and **[*166]** an MFC[B].

1. MFC[A] will include the allocated portion of credit and collection function costs and 50% of procurement-related call center function costs, plus A&G and rate base items associated with each of the above.

2. MFC[B] will include commodity purchasing function costs, allocated portions of advertising & promotions function costs and 50% of procurement-related call center function costs, plus A&G and rate base items associated with each of the above.

D. Full Service Customers .

Customers taking commodity service from the Company will be billed by Central Hudson for MFCT, which is equal to the sum of MFC[A] and MFC[B].

E. Retail Access Customers .

Customers that choose to purchase their commodity service from an energy services company (ESCO) that is participating in the Company's Purchase of Receivables (POR) Program will be billed by Central Hudson for MFC[A] only. The discount rate charged ESCOs that participate in Central Hudson's POR Program will be the same for all service classifications and will consist of an amount reflecting commodity-related uncollectibles costs and a time value of money factor of 0.25%. Customers that choose to purchase **[*167]** their commodity service from an ESCO that is not participating in the Company's POR Program will not be billed a MFC by Central Hudson.

F. Calculation of MFCs.

The electric and gas MFCs calculated under this Joint Proposal are set forth in Appendices C and F, respectively. These MFCs will be effective as of July 1, 2007 and remain in effect until changed by subsequent order of the Commission. Incremental revenue requirement amounts for RY2 and 3 will be recovered via delivery rate changes.

G. Short Run Avoided Costs.

At such time as total migration for a month exceeds 30% for either electric (SC 1 and 6) or gas (SC 1) customers, the Company will notify the Commission and the parties and convene discussions among the parties to develop short-run avoided cost curves. For RY2 and subsequent rate years, actual net lost revenues will be offset by the short-run avoided cost calculated from the avoided cost curves, if any; provided however, that no retroactive adjustment will be made prior to the time at which an average 30% migration level is sustained for 6 consecutive months.

H. Forecasting Participation and Reconciliation of Lost Revenues.

1. The forecast [*168] total retail access participation sales level for RY2 and RY3 for MFC 3 (S.C. 3 & 13) will be equal to the product of 1) the level of total sales eligible to participate in retail access during RY2 and RY3, respectively, and 2) the forecast retail access participation factor. The forecast retail access participation factor is equal to the total SC 3 and 13 retail access participation level, in kWh, for the months of December 2006 or 2007 (for, respectively, RY2 and RY3), divided by the level of SC 3 and 13 sales eligible to participate in retail access during the months of December 2006 or 2007 (for, respectively, RY 2 and RY 3).

2. For all other MFC categories, the forecast total retail access participation sales level for RY2 and RY3 will be calculated separately for each MFC category and will be equal to the product of 1) the level of total sales eligible to participate in retail access during RY2 and RY3, respectively, and 2) the forecast retail access participation factor. The forecast retail access participation factor will be separately calculated for each MFC category and is equal to the greater of a) the total retail access participation level, in kWh or Mcf, for the months [*169] of December 2006 or 2007 (for, respectively, RY2 and RY3), divided by the level of sales eligible to participate in retail access during the months of December 2006 or 2007 (for, respectively, RY2 and RY3) or b) the total retail access participation level, in kWh or Mcf, for the months of December 2006 or 2007 (for, respectively, RY2 and RY3), divided by the level of sales eligible to participate in retail access during the month of December 2006 or 2007 (for, respectively, RY2 and RY3), plus one-half the change in the retail access participation factor experienced during calendar year 2006 or 2007 (for, respectively, RY2 and RY3).

3. The change in the retail access participation factor equals the total retail access participation level, in kWh or Mcf, for the months of December 2006 or 2007(for, respectively, RY2 and RY3), divided by the level of sales eligible to participate in retail access during the months of December 2006 or 2007 (for, respectively, RY2 and RY3), minus the total retail access participation level, in kWh or Mcf, for the months of December 2005 or 2006 (for, respectively, RY2 and RY3), divided by the level of sales eligible to participate in retail access during [*170] the months of December 2005 or 2006 (for, respectively, RY2 and RY3).

4. At least 4 months prior to the beginning of RY2 and RY3, Central Hudson will serve on Staff and the parties to these proceedings its forecasts and calculations of the net lost revenues associated with the MFCs.

5. Forecast net electric and gas lost revenues for MFC 1 for RY2 and RY3 will be equal to the product of 1) the forecast total retail access participation sales level for RY2 or RY3, respectively, as calculated above, and 2) MFC[B]. Such calculations assume that all residential retail access customers are served by an ESCO participating in the Company's POR Program and, therefore, are charged MFC[A].

6. Forecast net lost revenues for the remaining MFC categories for RY2 and RY3 will be equal to the product of 1) the forecast total retail access participation sales level for RY2 or RY3, respectively, as calculated above, and 2) the MFC[T].

7. Central Hudson will recover forecast net lost revenues associated with customer migration from delivery and full service customers during RY2 and RY3. Central Hudson will recover 50% of the forecast net lost revenues from full service customers, on an MFC category-specific [*171] basis, by adding a separate component for that cost to MFC[B]. Central Hudson will recover the remaining 50% of forecast net lost revenues from electric delivery customers through a class-specific component of the Miscellaneous Charge Factor of the ECAM. For gas, Central Hudson will recover the remaining 50% of forecast net lost revenues from delivery customers through a new class-specific charge applicable to those customer classes subject to an MFC.

8. The actual net lost revenue for each MFC category for RY2 and RY3, respectively, will be equal to: 1) the actual total retail access participation sales level of customers taking service from ESCOs participating in Central Hudson's POR Program for RY2 or RY3, respectively, multiplied by 2) MFC[B], plus 3) the actual total retail access participation sales level of customers taking service from ESCOs not participating in Central Hudson's POR Program for RY2 or RY3, respectively, multiplied by 4) MFC[T].

9. At the end of RY2 and RY3, Central Hudson will calculate for each MFC category, the difference between the actual net lost revenues associated with retail access and the amount of net lost revenue recovered from customers.

[*172]
a) If the sum of the cumulative differences across MFC categories is negative (i.e., Central Hudson over-recovered net lost revenues from customers) , Central Hudson will defer the over-recovery, subject to carrying charges calculated at the authorized pre-tax rate of return, for future ratepayer benefit.

b) If the sum of the cumulative differences across MFC categories is positive (i.e., Central Hudson under-recovered net lost revenues from customers) , and the Company has not earned above the 10.6% earnings sharing threshold, Central Hudson will defer the under-recovery, subject to carrying charges calculated at the authorized pre-tax rate of return for future recovery.

c) If the Company has exceeded the 10.6% earnings sharing threshold, it will offset against the under-recovered net lost revenues its share of earnings that are in excess of the 10.6% threshold as described in Section IX.B.1. The amount of under-recovered net lost revenues remaining after the offset, if any, will be deferred subject to carrying charges at the utility's authorized pre-tax rate of return for future recovery.

I. Bill Format.

Central Hudson will propose, no later than October 1, [*173] 2006 an unbundled bill format for approval by the Commission. The schedule for cut-over to unbundled rates described above assumes prompt approval of the proposal, such that adequate time for programming changes will be available prior to July 1, 2007.

VII. CAPITAL EXPENDITURES

A. Electric Plant.

Central Hudson's electric capital expenditures, excluding the Allowance for Funds Used During Construction (AFUDC), will be set at a level of $ 158.078 million, reflecting $ 51.944 million for RY1, $ 52.530 million for RY2, and $ 53.604 million for RY3. If actual expenditures, excluding AFUDC, fall short of the cumulative total level of $ 158.078 million by the end of RY3, Central Hudson will defer for ratepayer benefit the amount of the shortfall multiplied by 1.5 times the average authorized pre-tax rate of return. Commencing on July 1, 2009, such deferral will be subject to carrying charges calculated at the authorized pre-tax rate of return.

B. Gas Plant, Exclusive of Gas Infrastructure Enhancements.

For Gas Plant, exclusive of Gas Infrastructure Enhancements addressed in Section XIII.G, Central Hudson's capital expenditures, excluding AFUDC, will be set at a [*174] presumed level of $ 27.495 million, reflecting $ 10.397 million for RY1, $ 9.354 million for RY 2, and $ 7.744 million for RY3. If actual expenditures, excluding AFUDC, fall short of the cumulative total level of $ 27.495 million by the end of RY3, Central Hudson will defer for ratepayer benefit the amount of the shortfall multiplied by 1.5 times average authorized pre-tax rate of return Commencing on July 1, 2009, such deferral will be subject to carrying charges calculated at the authorized pre-tax rate of return. If actual expenditures for Gas Infrastructure Enhancements exceed the $ 15.75 million cumulative total established in Section XIII.G, the amount above $ 15.75 million may be applied by Central Hudson to reduce any shortfall in this "Gas, Exclusive of Gas Infrastructure Enhancements" target.

C. Common Plant.

For Common Plant, Central Hudson's capital expenditures will be set, reflecting AFUDC, at a presumed level of $ 21.693 million, reflecting $ 7.732 million for RY 1, $ 7.031 million for RY 2, $ 6.930 million for RY 3. If actual expenditures, excluding AFUDC, fall short of the total level of $ 21.693 million by the end of RY 3, Central Hudson will defer for [*175] ratepayer benefit the amount of the shortfall multiplied by 1.5 times the average authorized pre-tax rate of return. Commencing on July 1, 2009, such deferral will be subject to carrying charges calculated at the authorized pre-tax rate of return.

VIII. DEPRECIATION

A. Depreciation Expense.

The average service lives, net salvage factors and life tables used in calculating the theoretical depreciation reserve and in establishing depreciation expense in the revenue requirements are set forth on Appendix J. The Company is authorized to use these factors until new factors are approved by the Commission. With respect to the period prior to June 30, 2006, the depreciation rates used are appropriately represented and will not be adjusted.

B. New Depreciation Study.

The Company will file a new depreciation study when it next files a major gas, electric or combined rate case.

1. If a combination gas and electric filing is made, the depreciation study will address gas, electric and common plant accounts; if the filing is limited to one line of business, the study need only address the plant accounts for that line.

2. The new study will include the following:
[*176]
a) Rolling and shrinking band analyses for each account shown in Appendix J that is applicable to the line of business being studied.

b) The width of the rolling and shrinking bands analyzed may be as determined by the Company, but in any event the rolling bands will not be greater than 10 years or less than 5 years.

c) The shrinking band analysis will start with all the data and decrease to one year of data.

d) Statistical results regarding Average Service Life each account will include:

e) Analyses of either ″h-type″ or ″Iowa-type″ curve fitting analyses and

f) The related ″fit index″ will be provided.

g) Plots of the observed and smoothed survivor curve for each account along with the fitted ″h-type″ or ″Iowa-type″ survivor curve.

h) The Depreciation Study will also include a Net Salvage Study for each plant account showing historical Gross Salvage, Cost of Removal and Net Salvage for each year of historical data included in the Net Salvage Study along with rolling band analysis results, with the width of the rolling band being five years.

3. The Company retains the right to submit additional analyses, and any recommendations, of its choice.

C. Negative Salvage [*177] .

The Company currently expenses the cost to remove gas mains and services when the cost exceeds 60% negative salvage.

1. During RY1 through RY3:

a) The 60% negative salvage limitation will not apply.

b) The Company will charge all costs associated with the removal of gas mains and services to the appropriate depreciation reserve account, and

c) The Company will charge to operating expense ratably over each of RY1 through RY3, $ 228,000, $ 233,000 and $ 238,000, respectively, with the offsetting credit to the same depreciation reserve accounts charged above. This provision expires at the end of RY3.

2. After the end of RY3, the Company will expense removal costs in excess of 60% negative net salvage absent the Commission's authorization to apply a different treatment; provided however, that the Company's agreement to apply such accounting after the end of RY3 in this Joint Proposal is understood to be without prejudice to any request the Company may make to the Commission to revise such accounting treatment after the end of RY3.

IX. DEFERRALS

A. Authorization.

The Company continues to be authorized to defer the following items for recovery in the [*178] next electric or gas, as appropriate, base rate change or other Commission-ordered disposition:

1. The Company is authorized to continue its use of deferral accounting with respect to the following expenses 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) Interest Costs on Variable Rate Debt;

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

e) Research and Development costs under Commission Technical Release No. 16(?).

f) Changes in accounting standards, subject to the understanding that this specific authority to defer is subject to such orders as the Commission may issue that provide for generic treatment of accounting practices;

2. Changes in federal or state regulations that have an impact [*179] of more than 1% of net gas or electric income;

3. Stray Voltage Program; and

4. Others addressed in this Joint Proposal.

5. The uses of deferral accounting authorized herein shall continue and shall not terminate because of the end of the term of this Joint Proposal.

6. It is recognized that certain of the deferrals provided for in this Joint Proposal, as listed at Appendix I, are subject to the Limitation of Deferral provision set forth under the heading "Earnings Sharing."

B. Right to Petition.

Central Hudson retains the right to petition the Commission for authorization to defer extraordinary expenditures not otherwise addressed by this Joint Proposal.

X. CAPITAL STRUCTURE AND EARNINGS SHARING

A. Capital Structure.

Appendix H shows the capital structure and allowed rates of return that have been incorporated into Appendices A and D.

B. Earnings Sharing.

1. In the event that Central Hudson achieves a regulatory rate of return on common equity above 10.60% in either the electric or gas department, on a July 1 through June 30 twelve-month basis commencing July 1, 2006, the earnings above 10.60% and up to 11.60% in such department(s) will [*180] be shared 50/50 respectively, between the Company and ratepayers.

2. In the event that Central Hudson achieves a regulatory rate of return on common equity above 11.60% in either the electric or gas department, on a July 1 through June 30 twelve-month basis commencing July 1, 2006, the earnings above 11.60% and up to 14.00% in such department(s) will be shared 35%/65% between the Company and ratepayers, respectively.

3. Any earnings above 14.00% will be deferred for the benefit of customers.

4. Carrying charges at the pre-tax authorized rate of return will be applied to the ratepayers' portion.

5. In the event that Central Hudson achieves a regulatory rate of return on common equity above 10.60% in either the electric or gas department, on a July 1 through June 30 twelve-month basis commencing July 1, 2006, and experiences an under-recovery of migration-related net lost revenues in such department, the net lost revenues will be offset by the Company's portion of the earnings above 10.60%. Central Hudson will defer any remaining net lost revenues for future recovery subject to carrying charges calculated at the authorized pre-tax rate of return. This calculation shall be made [*181] prior to the Limitation of Certain Deferrals described below.

6. Limitation on Certain Deferrals: When calculating the level of earned common equity return that may be subject to sharing after the calculation of lost revenues described above, the Company will make the following adjustment if its earnings exceed a 11.00 percent return on equity:

a) For earnings above 11.00 percent but less than or equal to 14.00 percent, the Company will reduce qualifying expenses (debits) deferred for later recovery by netting in the fashion described below, up to 50 percent of the deferral against the shareholders' portion of the earnings above 11.00 percent, provided that such reduction in deferrals will not cause the resulting earnings to decrease below an 11.00 percent return on equity.

b) The debit deferral amount for purposes of this provision will be determined by netting any credit deferrals against the qualifying debit deferrals.

c) The qualifying debit deferrals for purposes of this limitation are comprised of stray voltage, Research and Development, reductions to MDQ (as described in Section IV.C.l.e), variable rate interest, asbestos litigation costs, real property tax, gas balancing [*182] software, and ″general,″ meaning other deferrals not addressed in this Joint Proposal that individually exceed 1% of net income.

7. Measurement of Achieved Regulatory Rate of Return on Common Equity for Earnings Sharing Purposes:

a) Determinations of the achieved regulatory rate of return on common equity by department, for gas and electric operations, will be made separately for the twelve-month periods ending June 30.

b) The achieved regulatory return on common equity will be measured by department on the basis of Central Hudson's actual capitalization for the period being measured; provided, however, that if the actual equity ratio exceeds 47%, then a 47% equity ratio will be used for this purpose.

c) The financial consequences of any regulatory incentives, and other exclusions consistent with existing practices, will be excluded in determinations of regulatory rate of return on common equity.

C. Reporting.

Within 90 days following the end of a rate year, Central Hudson shall provide the Director of the Office of Accounting and Finance with a computation of achieved regulatory rate of return on common equity by department for the preceding period.

XI. [*183] ADDITIONAL RATE PROVISIONS

A. Accounting for Gas Mains/Services.

As of January 1, 2006, Central Hudson will implement revised accounting procedures that identify the type of material (i.e., plastic, steel, cast iron, etc.) used in the gas transmission mains, gas distribution mains and gas services recorded in Accounts 367, 376 and 380, respectively.

B. Balance Sheet Offsets

1. Projected electric and gas deferred debits and credits to be offset on June 30, 2006 are shown on Appendix G. The net electric deferred balance as of June 30, 2006 will be offset against the Excess Electric Depreciation Reserve. The actual electric balances at June 30, 2006 will be used to record the offset on July 1, 2006. The estimated net excess electric depreciation reserve remaining after offsets and use for rate moderation is also shown on Appendix G.

2. The net gas deferred balance as of June 30, 2006 will be recovered over a nominal seven-year period beginning July 1, 2007, the start of RY2; subject to adjustment to the amortization period as may be required in light of variances between the forecast and actual June 30, 2006 balances and recognition of gas ″make whole″ revenues. [*184] Appendix G, Schedule 2 shows the projected net gas balances. The actual gas balances at June 30, 2006 will be used to establish the amount to be recovered.

3. The gas net debit balance shown on Appendix G, Sheet 2 is comprised of a non-interest bearing component and an interest bearing component.

a) The non-interest bearing component is amortized on a straight-line basis over seven years beginning July 1, 2007, the start of RY2.

b) The balance of the interest-bearing component at July 1, 2007, is amortized over seven years, on a levelized basis recognizing accrued interest on the unamortized balance at the authorized pre-tax rate of return, beginning July 1, 2006.

C. Benefit Fund Cessation and Continuing Uses.

1. The Benefit Fund ceases as of June 30, 2006, and the funding previously established for the programs listed below will be preserved.

2. The existing approved uses of the Benefit Fund will continue as follows:

a) Rate base offset: $ 42.5 Million credit continues per prior Commission Order.

b) Economic Development: Central Hudson's Economic Revitalization Discount and Economic Development Program shall continue until revised by the Commission or [*185] program funding is exhausted. The remaining balance from the $ 11 million pre-tax set aside in the Commission's Economic Development Order issued October 3, 2002 in Case 00-E-1273, currently estimated at a projected June 30, 2006 pre-tax amount of $ 4.2 million, will continue to be available to be utilized in accordance with Central Hudson's Economic Revitalization Discount and Economic Development Program until such funding is exhausted or the Program is revised by the Commission. Central Hudson will notify Staff at such time as the Company estimates that the remaining unspent funds will be fully expended within six months.

c) Competitive metering: Remaining metering funding balances will be maintained as a stand-alone item reserved for spending on metering purposes.

D. Certain Rate Allowances .

The amounts shown on Appendix I will be used as the rate allowances for purposes of revenue matching accounting or other deferral purposes as appropriate.

E. East Fishkill Substation Deferral .

The Company will defer the revenue requirement differences between actual costs and the rate allowance for the East Fishkill Substation incorporated into Appendix A, for future [*186] recovery, or return to customers, subject to carrying charges calculated at the authorized pre-tax rate of return in either event. The rate allowance in RY3 for the East Fishkill substation is a placeholder for the actual value, which will not be known until a later time. In the event that the actual costs exceed the estimated costs, the Company will submit a report within 120 days of the project's in-service date detailing the reasons for the increased costs.

F. Electric Transmission ROW Maintenance.

If actual Electric Transmission ROW Maintenance expenditures during RY1 through RY3 are less than the total RY1 through RY3 level contained in rates of $ 6.723 million million by the end of RY3, Central Hudson will defer for ratepayer benefit the amount of the shortfall. Commencing July 1, 2009, such deferral will be subject to carrying charges calculated at the authorized pre-tax rate of return.

G. Electric Water Heating.

Central Hudson will file with the Commission, within 90 days following the Commission Order adopting this Joint Proposal, a proposed plan for unwinding the Company's electric water heating business and exiting from that business.

H. Make Whole [*187] .

The Company is authorized to record gas and electric revenues attributable to the extension of the suspension period. The electric revenues will be offset against the excess depreciation reserve. The gas revenues will be added to the amortization calculation.

I. MGP Site Investigation and Remediation Costs.

1. The rate allowances shown on Line 30 of Appendix A and Line 27 of Appendix D are established for MGP Site Remediation Costs.

2. The Company is permitted to defer for future recovery the differences between actual costs for MGP Site Investigation and Remediation Costs and the rate allowances, with carrying charges on the deferred balance (net of tax) for both debit and credit balances at the pre-tax authorized rate of return, including any remaining balance from the Deferred Gas Balances Offset and excluding accrued liabilities. Deferrable expenditures shall exclude Company labor and overhead charges.

3. Annual reporting requirements continue per existing Commission orders, including the Order issued October 25, 2002 in Case 01-G-1821.

J. Pension/ OPEBs.

1. Central Hudson has been subject to the Commission's Case 91-M-0890, Statement of Policy and [*188] Order Concerning the Accounting and Ratemaking Treatment for Pensions and Post-retirement Benefits other than Pensions (issued September 7, 1993) ("Pension and OPEB Policy Statement") and remains subject to the Pension and OPEB Policy Statement.

2. The Company has adopted Staff's position on year end treatment, and made appropriate adjustments on its books. Staff has withdrawn its other objections to the Company's accounting for pensions and OPEBs.

K. Property Taxes.

The Income Statements in Appendices A and D reflect forecasts of property taxes as rate allowances. The Company is permitted to defer the difference between actual property tax expenses and the forecasts for RY2 and

3 reflected in the Income Statements for future recovery. The differences (positive or negative) will be shared 90/10: Over-collections 90% customers/ 10% Company and under-collections 10% Company/90% customers. The Company will defer such under-collections and over-collections subject to carrying charges calculated at the Company's authorized pre-tax rate of return.

L. Ratemaking Factors.

1. The common cost allocation factor incorporated into Appendices A and D is 85% electric, 15% gas. [*189]

2. The electric loss factor incorporated into Appendix A is 1.0420.

3. The factor for lost and unaccounted for gas incorporated into Appendix D is 1.0159.

XII. LOW INCOME PROGRAM

A. New Low Income Program.

Central Hudson will institute a new Low Income Program to replace Central Hudson's current low income program ("Powerful Opportunities" or "POP"). The new program will proceed in two phases. The first phase will be an Interim Program that will replace the POP Program and will continue until the second phase ("Enhanced Powerful Opportunities" or "EPOP") is operational.

B. Program Funding and Administration.

1. Effective with the commencement of the Interim Program and continuing with the EPOP Program, Central Hudson will directly administer and manage its low income programs. The costs of administration and management, including staffing, will be included in program expenses and will be paid for through program funding.

2. Program funding for RY1 is $ 1.148 million, for RY2 is $ 1.32 million, and for RY3 is $ 1.50 million and, unless adjusted by Commission Order, for the rate years following will be $ 1.50 million.

3. Differences between the funding [*190] level and actual expenditure during a rate year will be deferred, with carrying charges calculated at the authorized pre-tax rate of return. If such differences are due to over-expenditures, the deferral will be limited to no more than 15% of the rate year funding level, for future recovery by the Company. If such differences are due to under-expenditures, the remaining balance will be rolled over for use in subsequent rate years for low income program expenditures.

C. Enhanced Powerful Opportunities.

Central Hudson and interested parties will work through a collaborative process to finalize the specific program design, and address implementation and other program issues for the Enhanced Powerful Opportunities Program. Work in this collaborative on some or all aspects of the EPOP program design will begin as soon as possible and no later than 10 days after the Commission's adoption of this Joint Proposal. Working with this collaborative, the Company will complete its development of a detailed EPOP program proposal within 45 days of the Commission's adoption of this Joint Proposal, which will be submitted for Commission approval. Once approved, the EPOP program implementation [*191] will be completed as soon as possible but no later than September 1, 2007.

1. The EPOP program design elements that the parties have agreed upon are:

a) Eligibility Criteria. The customer must:

(1) Use electricity or natural gas as the primary fuel for space heating.

(2) Be a HEAP recipient with the HEAP payment paid to Central Hudson.

(3) Have arrears of at least $ 100 remaining after the HEAP payment is applied to the customer's account.

(4) Enroll in the Central Hudson Budget Billing Program.

(5) Provide a Department of Social Services ("DSS") release for Central Hudson to receive income, expense and other family size verification, and such other information that may be necessary for implementation of the Program.

(6) Agree to be referred by Central Hudson to the New York State Energy Research and Development's ("NYSERDA") EmPower NY Program and to complete an application for participation.

(7) Renew HEAP eligibility annually.

b) Program Elements.

(1) In administering the EPOP Program, Central Hudson will refer participants to other local assistance programs and to NYSERDA's EmPower New York Program.

(2) The program will be initially designed to serve [*192] 800 to 1000 customers on an ongoing basis. Central Hudson will manage participation enrollment to the annual funding level available.

(3) Central Hudson will work with DSS to obtain income, expense and family size verification to determine participant eligibility.

(4) Central Hudson will have the discretion to include a customer in the program who does not meet all the eligibility criteria upon evidence that program participation will increase the likelihood that the customer will be able to maintain continuous service without compromising other essential household needs.

(5) Arrears forgiveness incentive. Collection activity on a participating customer's pre-program arrears will be suspended while the customer is in the program. One twenty-fourth (1/24) of a participating customer's arrears balance, up to a maximum of $ 100 per month, will be forgiven each month the customer pays current charges on time and in full. A customer failing to make a payment of current charges on time and in full will not receive any arrears forgiveness for that month. The customer may continue in the program for future months by paying the late bill and any associated late payment charges, and paying [*193] the bills in future months on time and in full. The arrears forgiveness funded from the program will be provided to program participants over a 24 to 36 month period, if the participant keeps the account current and makes 24 budget bill payments on or before their payment due dates.

(6) Customers will not be charged a late payment charge on their suspended arrears, but will be charged a late payment charge if they pay their budget payments late.

(7) Customers in the EPOP program will receive an annual bill discount based on their income level and family size. This annual discount amount will be provided over 12 months in monthly bills. The parties will develop the discount amounts and criteria during the collaborative process described above.

(8) Participants will exit the program upon completion of the arrears forgiveness provisions of the program or after 24 months, whichever comes later.

(9) The Program may be closed to further enrollment each year based on program costs and participant levels.

c) The format and schedule for reports will be agreed upon by the parties in the collaborative process described above. As part of the collaborative program design process, the [*194] Company and the parties also will describe the content for these reports and the data they will include. An evaluation plan will be developed by the parties for implementation such that the findings are available for consideration for planning regarding the Company's low income program subsequent to Rate Year 3.

d) Central Hudson will agree to convene a meeting with Staff and interested parties within 45 days of the conclusion of each rate year to review program operations, accomplishments and spending. If the parties and the Company agree that program modifications are needed, the Company will petition the Commission seeking approval to modify the Program accordingly.

D. Interim Program.

The parties agree that the Company's current POP program will be replaced by the Interim Program as soon as reasonably feasible. The Interim Program will be reflected in tariffs to be filed timely by the Company so that the Interim Program will be available to existing POP customers when the POP program ends. The Interim Program will have the following program design elements:

1. In administering the Interim Program, Central Hudson will refer participants to other local assistance [*195] programs and to the EmPower NY Program.

2. Interim Program Participants must agree to be referred by Central Hudson to NYSERDA's EmPower NY Program and to complete an application for participation.

3. The customers may participate in the program for up to 24 months or until the permanent program is in place, whichever is sooner.

4. Existing POP customers will be automatically enrolled into the interim program.

5. New participants must meet the eligibility requirements described above for the EPOP.

6. Participants must agree to budget billing for future bills.

7. Arrears forgiveness incentive. Collection activity on a participating customer's pre-program arrears will be suspended while the customer is in the program. One twenty-fourth (1/24) of the customer's arrears balance up to a maximum of $ 100 per month will be forgiven each month a participating customer pays current charges on time and in full. A customer failing to make a payment of current charges on time and in full will not receive any arrears forgiveness for that month. The customer may continue in the program for future months by paying the late bill and any associated late payment charges and paying the bills [*196] in future months on time and in full.

8. Customers will not be charged a late payment charge on their suspended arrears, but will be charged a late payment charge if they pay their budget payments late.

9. Discounted Customer Charge. The Interim Program will discount the customer charge for participants to $ 5.00 per month for gas service and to $ 5.00 per month for electric service ($ 10 total for dual service customers) .

10. Central Hudson will have the discretion to include a customer in the program who does not meet all the eligibility criteria upon evidence that program participation will increase the likelihood that the customer will be able to maintain continuous service without compromising other essential household needs.

11. Reporting.

a) Quarterly Reports.

(1) Central Hudson will provide Staff and other interested parties with a quarterly report on the Interim Program within 30 days of the end of each Program quarter. The reports will show the following information by month: the number of active program participants, the number of enrollments and departures, the total amount of customer service charge credits provided, amount of arrears forgiven, and administration [*197] costs.

(2) The quarterly reports may include such other information as the Company and the parties agree may be useful to evaluate the program's impacts on customers and on the Company.

(3) An overview of the level of program spending to date should be provided with the intent to keep a check on the level of program spending and budget.

b) Annual Reporting. In lieu of a quarterly report for the final operating quarter of the Interim Program in RY1, Central Hudson will prepare an annual report which will provide the same information as in the quarterly reports but on a rate year basis, as well as Central Hudson's assessment of program operations.

XIII. CUSTOMER SERVICE QUALITY PERFORMANCE MECHANISM

A. Effective Date.

The current mechanism set forth in the 2004 Rate Order will remain in effect through December 31, 2006. The new mechanism described below will become effective on January 1, 2007, for a potential total annual rate adjustment of 25 basis points. All basis point rate adjustments for this new mechanism will be calculated on a combined electric and gas basis.

B. Customer Satisfaction Index ("CSI").

1. Central Hudson will calculate its monthly [*198] and annual CSI performance consistent with the survey methodology defined in the Central Hudson document entitled "How Did We Do Survey" - Continuous Improvement through Monitoring Customer Satisfaction with Key Customer Processes.

2. Thresholds and rate adjustments for the CSI are:

CSI Annual Performance	Basis Points Rate Adjustment
85 or Higher	None
84 = CSI < 85	3.125
83 = CSI < 84	6.25
82 = CSI < 83	9.375
CSI < 82	12.5

C. PSC Complaint Rate.

1. The PSC complaint rate is the annual average of the number of monthly complaints per 100,000 customers.

2. The thresholds and rate adjustments are:

PSC Annual Complaint Rate	Basis Point Rate Adjustment
< 2.5	None
2.5	6.00
2.6	6.65
2.7	7.30
2.8	7.95
2.9	8.60
3.0	9.25
3.1	9.90
3.2	10.55
3.3	11.20
3.4	11.85
3.5	12.50

D. Appointments Kept.

The "Appointments Kept" penalty remains at $ 20 per missed appointment.

E. Evaluation of Telephone System Enhancements:

1. Central Hudson will conduct an evaluation of the "virtual hold" telephone enhancements it has made to its telephone answering procedures. The company will report on the results in July 2006, and January and June 2007.

2. Discussions [*199] among the parties will be held beginning in July 2007 regarding a possible telephone response metric (and redistribution of the existing 25 Basis Point rate adjustment for CSI/PSC Complaint Rate) to go into effect prospectively.

F. Reporting.

1. The Company will provide annual reports to the Director of the Office of Consumer Services (OCS) on its performance under each customer service quality performance measure within 45 days of the end of the reporting period. The annual report shall include information on whether any revenue adjustments are warranted under the Customer Service Quality Performance Mechanism.

2. A Report on the CSI for the period ending December 31, 2006 will be submitted within 45 days of the end of that year. It will include the presentation of quantitative and qualitative analysis of results, and the factors that the Company expects influenced the results, as well as the following:

a) The CSI margin of error calculated as shown in Appendix L.

b) Number and percent of responses received by each survey type;

c) Percent satisfaction for each survey question by survey type;

d) Any planned changes in customer service operations due to survey [*200] results; and

e) An appendix (based primarily on existing materials) that describes in detail the survey and analysis methodology will be included with the first annual report submitted.

3. Subsequent to the initial Report, the CSI Report will be filed on an annual basis with the Customer Service Quality Performance Mechanism Report. The company will convene a meeting with interested parties within 30 days of issuing the annual CSI Report to discuss the customer satisfaction survey and any changes in customer service operations proposed as a result of the survey.

XIV. GAS SAFETY MECHANISM

A. General.

All Gas Safety targets metrics are measured on a calendar year basis. The Gas Safety targets and rate adjustment levels applicable in calendar year 2006 are set in the 2004 Rate Plan. The calendar year 2008 Gas Safety targets set forth below will continue until changed by the Commission. Basis point rate adjustments will be calculated on the gas equity component of gas rate base that is shown on Appendix H, Schedule 2.

B. Leak Management.

1. For the calendar year ending December 31, 2007, Central Hudson will incur a rate adjustment if a year-end total leak [*201] backlog of 270 is exceeded, unless the Company repairs 340 leaks during that calendar year. The rate adjustment if the target thresholds are not met is 6 basis points.

2. For the calendar year ending December 31, 2008, Central Hudson will incur a rate adjustment if a year-end total leak backlog of 250 is exceeded, unless the Company repairs 340 leaks during that calendar year. The rate adjustment if the target thresholds are not met is 8 basis points.

C. Prevention of Excavation Damages.

1. Overall Damages.

a) For the calendar year ending December 31, 2007, Central Hudson will incur a rate adjustment if the year-end total of 5.9 excavation damages per 1000 One-Call Tickets is exceeded during that calendar year. The rate adjustment if the target threshold is not met is 2 basis points.

b) For the calendar year ending December 31, 2008, Central Hudson will incur a rate adjustment if the year-end total of 5.8 excavation damages per 1000 One-Call Tickets is exceeded during that calendar year. The rate adjustment if the target threshold is not met is 3 basis points.

2. Mismark Damages.

a) Mismarks will be determined based on Central Hudson's current procedures, [*202] including recognition of the Tolerance Zone as defined in 16 NYCRR Part 753-1.2(t).

b) For the calendar year ending December 31, 2007, Central Hudson will incur a rate adjustment if the year-end total of 0.9 excavation damages due to mismarks per 1000 One-Call Tickets is exceeded during that calendar year. The rate adjustment if the target threshold is not met is 5 basis points.

c) For the calendar year ending December 31, 2008, Central Hudson will incur a rate adjustment if the year-end total of 0.8 excavation damages due to mismarks per 1000 One-Call Tickets is exceeded during that calendar year. The rate adjustment if the target threshold is not met is 5 basis points.

D. Emergency Response.

For the calendar years ending December 31, 2007, and 2008, Central Hudson will incur a rate adjustment if the following targets for response to gas leak and odor calls are not met: (a) respond to 75% of all gas leak and odor calls within 30 minutes, (b) respond to 90% of all gas leak and odor calls within 45 minutes, and (c) respond to 95% of all gas leak and odor calls within 60 minutes. The rate adjustments if the target thresholds are not achieved, are as follows: 2007 - 3 [*203] basis points for the 30 minute response time and 2 basis points for each of the 45 and 60 minute response times; 2008 and thereafter - 3 basis points for each of the 30, 45, and 60 minute response times.

E. Gas Infrastructure Enhancement.

1. A target of $ 15.75 million is established for expenditures on Gas Cast Iron/Steel pipe replacement over the three-year period of the Rate Plan, subject to expenditure of no less than $ 4.5 million in each calendar year, ending 12/31/2009.

2. The $ 15.75 million amount is comprised of the costs of installation and removal of Gas Cast Iron/Steel pipe replacement associated among: (1) the total category of New Business Gas Service Replacements blanket work orders, (2) the total category of Distribution Improvements Cast Iron Main Replacements blanket work orders, (3) the total category of Distribution Improvements Main Replacement blanket work orders, and (4) the summation of individual Distribution Improvement specific projects involving the replacement of non-plastic gas main.

3. If actual expenditures fall short of the total $ 15.75 million target level by the end of 2009, Central Hudson will defer for ratepayer benefit the amount [*204] of the shortfall multiplied by 1.5 times average authorized pre-tax rate of return. Such deferral shall represent the sole remedy against the Company for failure to make expenditures at the total forecast level for replacement of cast iron and steel mains and services in the categories set forth in subsection 1 above. Commencing on January 1, 2010 such deferral will be subject to carrying charges calculated at the authorized pre-tax rate of return.

4. The $ 15.75 million target exceeds Central Hudson's forecast of construction costs for these items by $ 1.15 million. That amount is included in the forecast rate base included in the Income Statements in Appendix D.

F. Reporting.

1. Central Hudson will, by January 31st of each year, file a report with the Director of the Office of Gas & Water on its performance in meeting each of the above Gas Safety mechanisms.

2. By August 1 of each calendar year under this Joint Proposal, the Company will file a progress report with the Director of the Office of Gas & Water on its performance in meeting each of the above Gas Safety mechanisms.

3. The Company will cooperate with Staff in making back-up records and documentation related [*205] to the targets available for review and verification.

XV. ELECTRIC RELIABILITY

A. SAIFI And CAIDI Targets .

Effective January 1, 2006, for each calendar year, the target for the Customer Average Interruption Duration Index (CAIDI) is set at 2.50, and the target for the System Average Interruption Frequency Index (SAIFI) is set at 1.45.

1. A rate adjustment of 10 basis points (electric) will be assessed against Central Hudson for each failure to satisfy an annual target threshold.

2. Outages caused by ″Major Storms,″ as defined at 16 NYCRR § 97.1, and the following events, are excluded from the calculation of the indices:

a) Any incident resulting from a strike or a catastrophic event beyond the control of the Company, including but not limited to plane crash, water main break, or natural disaster (e.g., hurricane, flood, earthquake). This exclusion does not include heat-related outages.

b) Any incident where a problem beyond the Company's control involving generation or the bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as [*206] a result of unsatisfactory performance by the Company.

B. Other Electric Reliability Targets .

In addition to the SAIFI and CAIDI targets, reliability-oriented targets for significant construction projects targets are established as follows:

1. Central Hudson will be assessed a rate adjustment of 5 basis points (electric) for RY1, RY2, and RY3, if it does not complete 100 circuit miles of enhanced distribution line clearing during each respective RY. Lines eligible for enhanced clearing are the 300 miles of circuits that were not cleared previously under the Full Circuit Mainline Program that was part of the Enhanced Reliability Program approved in the 2001 Rate Plan.

2. Central Hudson will be assessed a rate adjustment of 5 basis points (electric) if it does not complete and energize its proposed East Kingston substation by June 30, 2007.

3. Central Hudson will be assessed a rate adjustment of 5 basis points for failing to complete reliability-related construction projects in calendar years 2007 and 2008, respectively, similar to the project described in (2) above that will be identified by Staff by January 1, 2007 and 2008, respectively, from among the electric [*207] reliability-related projects identified in the Company's updated capital forecasts, which will be presented to Staff during the third quarter of 2006 and 2007, respectively, in the meetings referred to below.

C. Other Provisions.

1. The Company will, following the Commission's adoption of this Joint Proposal, petition the Commission for permission to withdraw the Company's pending petition for rehearing of the Commission's Order issued September 30, 2005 concerning electric reliability. The 37.5 basis points penalties for not meeting reliability target

thresholds in 2002 and 2004 are reflected in Appendix G. Upon Commission adoption of this Joint Proposal, the Company is authorized to reverse the previous entry of the 2005 reliability penalty.

2. A forecast of 855 employees was recognized in rates for the purpose of allowing Central Hudson to fund the hiring of additional line mechanics.

3. Staff and the Company will meet quarterly in Company operating areas to discuss reliability and employee levels and utilization.

4. The Company will report on its compliance with electric reliability targets within 45 days of the end of each calendar year.

5. This reliability [*208] performance mechanism will remain in place until a subsequent approach is adopted by the Commission.

XVI. MONTHLY METER READING/BILLING STUDIES

A. Monthly Billing Study.

Central Hudson will develop and file with the Commission within 150 days following Commission adoption of this Joint Proposal, a study of the costs and benefits of converting from bi-monthly meter reading and billing to monthly meter reading and billing for all customers using existing metering. The study will identify the one-time and on-going incremental costs associated with the conversion to monthly metering and billing and the net effect on the Company revenue requirements. The study will include an implementation plan detailing the period of time that would be needed to accomplish the conversion. The study maybe updated following the completion the AMR Pilot described below.

B. AMR Pilot.

Central Hudson will develop and file with the Commission by January 1, 2007, an Automated Meter Reading (AMR) Pilot proposal, which will have the following characteristics:

1. The AMR Pilot will include 5000 meters (gas and electric combined).

2. A fixed network meter technology will be utilized.
[*209]
3. The Pilot will be funded from the unused competitive metering funds held in the Benefit Fund, or excess depreciation reserve, up to a total program cost of $ 1,500,000.

4. Quarterly status reports will be filed with the Director of OCS providing the program status and costs.

5. A final report summarizing the results of twelve months of operational experience, and making any appropriate recommendations, will also be submitted.

C. Reporting.

Following completion of the final report on the AMR Pilot, Central Hudson may update the study discussed above, to reflect any demonstrated benefits to be realized from implementation of monthly meter reading and billing using AMR technology, and make any appropriate recommendations to the Commission.

XVII. RETAIL ACCESS

A. Market Match Program.

The Market Match Program will continue, consisting of following elements:

1. A system on Central Hudson's Web site enabling the exchange of customer usage data with ESCOs for customers interested in obtaining competitive price offers from ESCOS.

2. Notification informing all non-residential customers of the Program annually via bill inserts or other mailings.

3. [*210] Responses from customers via the Web site indicating their interest in receiving solicitations for competitive price commodity options, contact information, and authorization for Central Hudson to provide the customer's service class, historical demand, energy consumption, etc. to participating ESCOs.

4. ESCO access to Central Hudson's Web site via a secure Web page that will allow ESCOs to obtain participating customer information and solicit customers by providing competitive price options.

5. Provisions for customers to exit the Market Match Program at any time via the Web site.

B. Market Expo Program.

The Market Expo Program will continue, consisting of the following elements:

1. The Market Expo will continue to bring the ESCOs, business customers, and Central Hudson together to provide a forum for an exchange of customer data for customers interested in obtaining a competitive price.

2. The Expo will also provide a setting for customers to meet with ESCOs during the day.

3. Staff and Central Hudson will work together to develop the work plan for the Market Expo Program.

4. The work plan will detail how a maximum of two Expos annually should be held, [*211] the dates of the Expos, and describe the customers that will be invited.

5. E-mail and/or program announcement letters for ESCOs and customers will be developed and sent out at least two weeks prior to the event(s).

6. Central Hudson will:

a) Invite all non-residential utility commodity customers sized greater than 100 kW to the Expo.

b) Conduct Expos that include giving an overview presentation on the status of the electricity and gas markets in New York, along with an explanation of Central Hudson's retail access rules.

C. Energy Fairs.

1. One or two Energy Fairs will be conducted annually by the Company, in collaboration with Staff and ESCOs, prior to the winter heating season in each rate year.

2. Staff, the Company, and ESCOs will meet at least one month prior to the Energy Fairs to discuss the administrative details and logistics of the event.

3. Central Hudson will:

a) Secure the location and fund the reasonable logistics costs for the Energy Fair.

b) Provide for adequate signage at the location to direct customers to the event.

c) Issue invitations to targeted residential and small commercial customers to attend the event at least two weeks [*212] prior to the event.

d) Issue a press release publicizing the event at least two weeks prior to the event.

e) Invite ESCO participation and arrange for reasonable and appropriate ESCO facilities at the event. At least two ESCOs offering residential commodity service must agree to participate in the Energy Fairs prior to advertising the event to the public.

f) Current utility customer account data will be made accessible to the customer by the Company at the site of an Energy Fair.

D. ESCO & Marketer Satisfaction Mechanism.

1. Central Hudson will conduct annually a telephone or e-mail survey, with a goal of attempting to maintain its current 100% ESCO participation in the survey.

2. Central Hudson will report to the Office of Retail Market Development within 60 days after the survey is conducted, on the results of the survey and its plans for addressing marketer concerns, if any, which were expressed in the survey.

E. ESCO Ombudsman.

1. The existing Ombudsman program will continue.

2. Central Hudson shall report quarterly on all ESCO contacts to the Ombudsman to the Director of the Office of Retail Market Development, including a brief description of any [*213] issues and concerns expressed to the Ombudsman.

F. Competition Awareness and Understanding Survey.

1. Central Hudson will continue to survey a sample of its residential customers annually for the purpose of tracking changes in customer awareness and understanding of competition in electricity and gas markets.

2. The Company will report the results of the survey to the Office of Retail Market Development as a component of its report on its outreach and education plan.

G. Competition Education Campaign.

Central Hudson's rate allowance includes $ 350,000 in each of the Rate Years ending June 30, 2007, June 30, 2008, and June 30, 2009 for spending on a competition education campaign aimed at promoting customer migration. The Company will develop the campaign in collaboration with Staff and interested ESCOs. Actual expenditure shortfalls below the $ 350,000 rate allowances will be deferred for expenditure on the same purposes in future rate years.

H. ESCO Referral Program.

This Joint Proposal does not affect Central Hudson's ESCO Referral Program, which was approved in an Order issued December 22, 2005 in Case 05-M-0332; provided, however, that incremental [*214] costs incurred in implementing the Energy Switch Program to July 1, 2006 will be deferred for future recovery subject to carrying charges at the authorized pre-tax rate of return.

XVIII. Further Understandings Between Central Hudson and USMA.

A. Best Efforts.

Central Hudson and USMA will mutually use best efforts to accomplish the following by June 1, 2006:

1. Provision by Central Hudson to USMA of a quit claim deed, in recordable form, to USMA for all regulators, valves and pipelines and all other natural gas facilities located between Crow's Nest and Thayer Gate, except for the existing six meters (5 for the material balance for USMA and one for Hotel Thayer) along with directly associated regulators and valves supporting these meters.

2. Provision by either USMA or the Army Corps of Engineers, on behalf of USMA, of a written authorization that confirming that, pending receipt of the easement referred to below, CHGE is authorized

by the government to have installed its pipelines and other facilities up to Crow's Nest, and that CHGE has the right to enter for purposes of maintenance and repair, subject to reasonable notification procedures.

B. Easement [*215] .

USMA will support CHGE's request for a 50 year standard government easement before the U. S. Army Corps of Engineers for CHGE's pipeline facilities to Crow's Nest and request expedited issuance.

C. Refunds of Taxes.

Central Hudson will cooperate with USMA concerning USMA's efforts to receive refunds of taxes that have been charged to USMA in CHGE's gas rates for which USMA believes it is not liable; subject to the understandings that the responsibility for identifying the taxes that USMA is interested in and all relevant information (aside from information related to Central Hudson's rates) rests with USMA, that Central Hudson will not perform any legal research for USMA in connection with USMA's tax status, that Central Hudson will not be obliged to make any representations to any taxing authorities as to USMA or USMA's tax status, that Central Hudson makes and will make no representations to USMA concerning USMA's tax responsibility, and that any tax refunds which CHGE receives will be subject to Section 113(2) of the Public Service Law.

D. Cost of Service Study.

When it next files a new general combined or gas rate case, the Company will include in its [*216] gas cost of service study identification of those costs attributable to serving USMA and include with its rate design rates for USMA, or its parent service classification, based on no greater than a 100% revenue allocation of those costs to USMA and based on no greater than a 1.0 factor for application of any system average increase requested; provided, however, that nothing in this provision shall preclude the Company from filing and advocating such cost of service, class rates of return, revenue allocation or rate design as it may deem appropriate.

E. Reporting.

Subsequent to the time it receives the easement referred to above, Central Hudson will provide to the West Point Contracting Officer an annual report of maintenance, testing, maintenance and repair of all Central Hudson-owned facilities located on-post. The report will be due by February 1 for all such activities conducted during the prior calendar year.

XIX. TERMS AND CONDITIONS

A. Complete Resolution.

This Joint Proposal is intended to be a complete resolution of all issues in Cases 05-E-0934 and 05-G-0935. The Signatories to the Joint Proposal agree that the provisions of the Joint Proposal are, [*217] in aggregate, a reasonable resolution of each of the proceedings. Each provision hereof is in consideration and support of all the other provisions, and each Signatory has expressly conditioned its support upon the acceptance of this Joint Proposal in its entirety by the Commission.

B. Reservation.

In the event that the Commission alters any provision of the Joint Proposal, each Signatory will be deemed to have fully reserved its rights to contest the altered Joint Proposal, and any such alteration.

C. Integrated Document.

This Joint Proposal is an integrated whole, with each provision in consideration for, in support of, and dependent on the others. Thus, if the Commission does not approve this Joint Proposal in its entirety without modification, each of the Signatories reserves the right to withdraw its participation and support by serving written notice on the Commission and the other Signatories and, if necessary, to litigate, without prejudice, any or all issues as to which such Signatory agreed in this Joint Proposal; in such event, any such Signatory shall not be bound by the provisions of this Joint Proposal, as executed or as modified.

D. Dispute Resolution [*218] .

In the event of any disagreement over the interpretation of this Proposal or the implementation of any of the provisions hereof, which cannot be resolved informally among the Signatories, such disagreement shall be resolved in the following manner: The Signatories shall promptly convene a conference and in good faith shall attempt to resolve such disagreement. If any such disagreement cannot be resolved by the Signatories, an affected Signatory may petition the Commission for relief on a disputed matter.

E. Non-Precedent.

None of the terms and provisions of this Joint Proposal and none of the positions taken herein by any party may be cited or relied upon by any other party in any fashion as precedent in any proceeding before the Commission, or before any other regulatory agency or any court of law for any purpose, except in furtherance of the purposes and results of the Signatories' settlement.

F. Application for New Rates.

Central Hudson may file an application(s) for new rates at any time, provided that any such rates will not become effective until after June 30, 2009. Nothing in this provision shall affect the Commission's authority to suspend the effective [*219] date of a rate filing.

G. Safe and Adequate Service.

Central Hudson may petition for new rates at any time on the grounds that without new rates safe, adequate and reliable service at just and reasonable rates would be jeopardized.

H. Continued Effect.

Unless otherwise provided herein, the provisions of this Joint Proposal shall remain in effect until changed by the Commission.

WHEREFORE, this Joint Proposal has been agreed to as of the 17th day of April, 2006, by and among the following, each of whom, by its signature, represents that it is fully authorized to execute this Joint Proposal and, if executing this Joint Proposal in a representative capacity, that it is fully authorized to execute it on behalf of its principal(s).

ATTACHMENT II

Appendix A, Schedule 1

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Electric Income Statements

($ 000)

	Rate Years Ending			
		6/30/07	**6/30/08**	**6/30/09**
Line No.		**(A)**	**(B)**	**(C)**
	Operating Revenues			

Line No.	Rate Years Ending	6/30/07 (A)	6/30/08 (B)	6/30/09 (C)
1	Delivery Revenues - Before Increase	$ 170,486	$ 215,741	$ 225,615
2	Rate Increase - Before Moderation	41,383	6,121	5,529
3	Other Operating Revenues	6,145	6,172	6,196
4	Total Operating Revenues	218,014	228,034	237,340
	Operating Expenses			
5	Production Maintenance	143	146	149
6	Transmission Right of Way Maintenance	2,187	2,240	2,296
7	Distribution Right of Way Maintenance	7,804	8,116	8,442
8	Labor	38,920	39,955	40,966
9	Research and Development	1,846	1,857	1,860
10	Expenses Projected Based on Inflation	9,249	9,452	9,660
11	Miscellaneous General Expenses	2,408	2,453	2,498
12	Transportation Depreciation	1,334	1,363	1,393
13	Fringe Benefits	6,011	6,158	6,329
14	Other Post Employee Benefits	8,382	8,382	8,382
15	Pension Plan	10,568	10,568	10,568
16	Contract Rents	2,120	2,167	3,414
17	Uncollectible Accounts	1,199	1,250	1,297
18	Regulatory Commission Expenses	1,349	1,379	1,409
19	Data Processing Expense	3,000	3,066	3,133
20	Other Operating Insurance	1,440	1,472	1,504
21	Telephone	1,550	1,583	1,618
22	Legal Services	2,316	2,367	2,419
23	Special Services	1,483	1,516	1,549
24	Injuries and Damages	1,959	2,002	2,046
25	Storm Expense	5,197	5,311	5,428
26	Environmental	309	316	323
27	Powerful Opportunities Program	976	1,125	1,275
28	Expenses Allocated to Affiliates	(491)	(502)	(513)
29	Stray Voltage Testing	2,200	2,250	2,300
30	MGP Remediation Cost Recovery	-	1,400	1,400
31	Recovery of Net Regulatory Assets	-	-	-
32	Competition Education Program	298	298	298
33	Productivity	(149)	(149)	(149)
33	Total Operating Expenses	113,608	117,541	121,296
34	Other Deductions			
35	Property Taxes	19,758	20,460	21,183
36	Revenue Taxes	3,712	3,963	4,197
37	Payroll Taxes	2,953	3,018	3,084
38	Other Taxes	1,254	1,282	1,310
39	Depreciation	21,682	22,554	23,746
40	Moderator - Amortize Excess Reserves	-	-	-
41	Total Other Deductions	49,359	51,277	53,520
42	State Income Taxes	2,942	3,099	3,184

	Rate Years Ending	6/30/07	6/30/08	6/30/09
Line No.		(A)	(B)	(C)
43	Federal Income Taxes	13,753	15,130	15,450
44	Total Income Taxes	16,695	18,230	18,634
45	Total Operating Revenue Deductions	179,662	187,048	193,450
46	Operating Income	$ 38,353	$ 40,986	$ 43,890
47	Rate Base	$ 544,007	$ 578,065	$ 615,375
48	Rate of Return	7.05%	7.09%	7.13%

[*220]

Appendix A, Schedule 2

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Electric Rate Increase Phase-In

($ 000)

	Rate Years Ending	6/30/07	6/30/08	6/30/09
Line No.		(A)	(B)	(C)
	Electric Rate Increase Phase-In:			
1	Required Electric Rate Increases	$ 41,383	$ 6,121	$ 5,529
	Moderation of Rate Increases:			
2	RY1 Moderation	(23,495)	23,918	
3	RY2 Moderation		(12,150)	12,357
4	RY3 Moderation			0
5	Phase-In Electric Rate Increases	$ 17.888	$ 17.889	$ 17.888
	Use of Moderators:			
6	Amount of Moderators	($ 22,887)	($ 11,840)	$ 0
7	/ Gross up Factor	0.97410	0.97410	0.97410
8	Revenue Requirement	($ 23,495)	($ 12,150)	$ 0
	Loss of Revenue Growth Due to Phase-In:			
9	RY1 Moderation	($ 23,495)		
10	x Revenue Growth Rate	1.018 =	$ 23,918	
11	RY2 Moderation		(12,150)	
12	x Revenue Growth Rate		1.017 =	$ 12,357

Appendix A, Schedule 3

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Electric Rate Base

($ 000)

Electric Rate Years Ending	**6/30/07**	**6/30/08**	**6/30/09**
Book Cost of Utility Plant	$ 862,277	$ 907,246	$ 960,008
Less: Accumulated Provision for Depreciation and Amortization	(302,582)	(314,239)	(327,595)
Net Plant	559,695	593,007	632,413
Noninterest-Bearing Construction Work in Progress	39,705	44,887	48,105
Preliminary Survey & Investigation	0	0	0
Customer Advances for Undergrounding	(179)	(179)	(179)
Deferred Charges	14,978	14,773	13,347
Accumulated Deferred Federal Taxes	(90,257)	(94,567)	(98,715)
Accumulated Deferred State Taxes	(2,739)	(3,468)	(4,206)
Working Capital	30,425	31,232	32,232
Unadjusted Rate Base	551,628	585,686	622,996
Capitalization Adjustment to Rate Base	(7,621)	(7,621)	(7,621)
Total	$ 544.007	$ 578.065	$ 615.375

[*221]

ATTACHMENT III

Appendix B

[SEE TABLE IN ORIGINAL]

ATTACHMENT IV

Appendix C

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Summary of Proposed Monthly Electric Delivery Rates

(Excludes S.C. Nos. 5 & 8)

	Current Rates	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
S.C. No. 1				

		Current Rates	Rate Year 1	Rate Year 2	Rate Year 3
	Customer Charge	$ 12.00	$ 13.50	$ 15.00	$ 16.00
	kWh	$ 0.03167	$ 0.03523	$ 0.03544	$ 0.03955
S.C. No. 2 - Non-Demand					
	Customer Charge	$ 14.00	$ 16.00	$ 18.00	$ 20.00
	kWh	$ 0.01432	$ 0.01583	$ 0.01662	$ 0.01810
S.C. No. 2 - Secondary					
	Customer Charge	$ 20.00	$ 23.50	$ 27.00	$ 30.00
	kWh	$ 0.00486	$ 0.00501	$ 0.00431	$ 0.00431
	kW	$ 6.18	$ 6.61	$ 7.07	$ 7.53
S.C. No. 2 - Primary					
	Customer Charge	$ 80.00	$ 90.00	$ 100.00	$ 110.00
	kWh	$ 0.00107	$ 0.00116	$ 0.00126	$ 0.00135
	kW	$ 4.61	$ 4.91	$ 4.94	$ 5.23
S.C. No. 3					
	Customer Charge	$ 250.00	$ 400.00	$ 400.00	$ 400.00
	kWh	$ 0.00250	$ -	$ -	$ -
	kW	$ 5.22	$ 6.69	$ 7.05	$ 7.49
	Rkva	$ 0.44	$ 0.44	$ 0.44	$ 0.44
S.C. No. 6					
	Customer Charge	$ 12.00	$ 14.50	$ 17.00	$ 19.00
	On-Peak kWh	$ 0.06423	$ 0.06708	$ 0.06418	$ 0.06751
	Off-Peak kWh	$ 0.02141	$ 0.02236	$ 0.02139	$ 0.02250
S.C. No. 9 - Traffic Signals					
	Charge per Signal Face	$ -	$ 1.90	$ 2.10	$ 2.40
S.C. No. 13 - Substation					
	Customer Charge	$ 500.00	$ 500.00	$ 500.00	$ 500.00
	kWh	$ 0.00150	$ -	$ -	$ -
	kW	$ 2.90	$ 4.18	$ 4.52	$ 4.98
	Rkva	$ 0.44	$ 0.44	$ 0.44	$ 0.44
S.C. No. 13 - Transmission					
	Customer Charge	$ 500.00	$ 500.00	$ 500.00	$ 500.00
	kWh	$ 0.00100	$ -	$ -	$ -
	kW	$ 1.52	$ 2.39	$ 2.51	$ 2.75
	Rkva	$ 0.44	$ 0.44	$ 0.44	$ 0.44

[*222]

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

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	2,978,064	3,000,048	3,020,808

		Rate Year 1	Rate Year 2	Rate Year 3
	kWh	2,074,960,000	2,123,820,000	2,168,620,000
S.C. No. 2 - Non-Demand	Customer Months	339,696	341,112	342,648
	kWh	185,770,000	187,020,000	188,290,000
S.C. No. 2 - Secondary	Customer Months	140,364	143,964	147,936
	kWh	1,463,470,000	1,501,650,000	1,537,710,000
	kW	4,685,870	4,808,210	4,923,750
S.C. No. 2 - Primary	Customer Months	2,100	2,148	2,184
	kWh	235,970,000	240,630,000	244,970,000
	kW	636,180	648,750	660,450
S.C. No. 3	Customer Months	540	552	564
	kWh	379,190,000	385,910,000	392,270,000
	kW	861,380	876,650	891,130
	Rkva	115,280	117,320	119,230
S.C. No. 6	Customer Months	30,720	30,720	30,720
	On-Peak kWh	18,360,000	18,360,000	18,360,000
	Off-Peak kWh	35,640,000	35,640,000	35,640,000
S.C. No. 9 - Traffic Signals	Signal Face Months	30,734.16	30,734.16	30,554.95
S.C. No. 13 - Substation	Customer Months	84	84	84
	kWh	165,620,000	165,620,000	165,620,000
	kW	302,507	304,716	304,716
	Rkva	37,250	37,250	37,250
S.C. No. 13 - Transmission	Customer Months	96	96	96
	kWh	1,135,560,000	1,134,220,000	1,136,850,000
	kW	1,839,929	1,907,337	1,911,580
	Rkva	56,140	56,140	56,140

[*223]

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Electric Commodity Related Merchant Function Charges

	Applicable to S. C. No.	MFC[A] $/kWh	MFC[B] $/kWh	MFC[T] $/kWh
MFC-1	1 & 6	0.00145	0.00176	0.00321
MFC-2	2	0.00037	0.00035	0.00072
MFC-3	3 & 13	0.00013	0.00008	0.00021
MFC-4	5, 8 & 9	0.00013	0.00069	0.00082

Notes:

1. Customers taking commodity service from Central Hudson will be billed by Central Hudson for MFC[T], which is equal to the sum of MFC[A] and MFC[B].

2. MFC[A] will include the allocated portion of collection function costs and 50% of procurement-related call center function costs, plus administrative & general and rate base items associated with each of these items. Customers that choose to purchase their commodity service from an energy services company (ESCO) that is participating in Central Hudson's Purchase of Receivables (POR) Program will be billed by Central Hudson for MFC[A] only.

3. MFC[B] will include commodity purchasing function costs, allocated portions of advertising & promotions function costs and 50% of procurement-related call center function costs, plus administrative [*224] & general and rate base items associated with each of these items.

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Electric & Gas Embedded Cost of Service Studies

Summary of Revisions to Exhibits (LGA-1) & (LGA-2):

. The delivery/ commodity relationship used for the functionalization of certain unbundled costs within the electric and gas embedded cost of service studies was revised to reflect the delivery/ commodity relationship of revenues for the twelve months ended December 31, 2005.

. Procurement Function -- The Company developed a new allocation factor to replace the ″ENERGY″ COS class allocation factor for the ″Procurement Function″ shown on Exhibits (LGA-2), Schedule C, Page 1 (electric) and (LGA-1), Schedule C, Page 1 (gas). The new allocator is a blended factor that attributes the components of the procurement function to the COS classes as follows:

. CHG&E Commodity-buyers costs -- allocated to classes on ENERGY as per the company's negotiated revisions to the rate year # 1 sales forecast by class;
. Credit and Collections on Commodity -- allocated to the COS classes on number of customers via the CODBT allocation [*225] factor;
. Call Center costs related to Commodity - allocated to COS classes on number of customers via CODBT allocation factor.

. Delivery Service Uncollectibles, Credit and Collections:

. All of Line 28 was redistributed vertically within each COS class to all other functions except ″Procurement″ re: Exhibit (LGA-1), Schedule C, Page 1 (gas);

. All of Line 31 was re-distributed vertically within each COS class to all functions other than ″Procurement″. re: Exhibit (LGA-2), Schedule C, Page 1.

. The amount originally (mistakenly) attributed to electric O&M account 565 was re-distributed among the other O&M Transmission accounts;

. Gas [1] and Electric demand, sales, revenue and customer allocators were revised to reflect Staff and Company revisions to the gas and electric sales forecasts. The demand allocators for SD, PD, LGP, LGS and LGT were developed from Ms. Bunt's forecasts;

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[1] Some specific changes included elimination of < 6″ lines from West Point gross plant; reduction of West Point MDQ from 7104 to 5833 Mcf; reduction in SC11 transmission customers and sales due to closure of IBM West complex.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

. The classification of electric distribution lines was revised per agreement with Staff witness Allen;
. The inputs to the gas and electric rate year # 1 COS studies were revised to reflect Staff rate year # 1 Income Statement changes to rate base, revenues, O&M and taxes [*226] as provided to the Company for electric and gas.

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Comparison of Present and Proposed Electric Rates

Single Phase Residential Service Service

Classification No. 1 - General Service

Energy kWh	Present Rates	Proposed Rates	Change ($)	Change (%)
-	$ 12.29	$ 13.82	$ 1.54	12.50%
12	$ 13.48	$ 15.06	$ 1.58	11.72%
25	$ 14.77	$ 16.40	$ 1.63	11.02%
50	$ 17.25	$ 18.97	$ 1.72	9.96%
75	$ 19.73	$ 21.54	$ 1.81	9.17%
100	$ 22.21	$ 24.11	$ 1.90	8.56%
132	$ 25.39	$ 27.41	$ 2.02	7.94%
150	$ 27.18	$ 29.26	$ 2.08	7.66%
175	$ 29.66	$ 31.83	$ 2.17	7.33%
200	$ 32.14	$ 34.40	$ 2.26	7.05%
250	$ 37.10	$ 39.55	$ 2.45	6.60%
300	$ 42.07	$ 44.69	$ 2.63	6.25%
350	$ 47.03	$ 49.84	$ 2.81	5.98%
400	$ 51.99	$ 54.98	$ 2.99	5.76%
450	$ 56.95	$ 60.13	$ 3.18	5.58%
500	$ 61.92	$ 65.28	$ 3.36	5.42%
600	$ 71.84	$ 75.57	$ 3.72	5.18%
700	$ 81.77	$ 85.86	$ 4.09	5.00%
800	$ 91.69	$ 96.15	$ 4.45	4.86%
900	$ 101.62	$ 106.44	$ 4.82	4.74%
1,000	$ 111.55	$ 116.73	$ 5.18	4.64%
1,200	$ 131.40	$ 137.31	$ 5.91	4.50%
1,500	$ 161.18	$ 168.18	$ 7.00	4.35%
2,000	$ 210.81	$ 219.63	$ 8.83	4.19%
2,500	$ 260.43	$ 271.08	$ 10.65	4.09%
3,000	$ 310.06	$ 322.54	$ 12.47	4.02%
3,500	$ 359.69	$ 373.99	$ 14.29	3.97%
4,000	$ 409.32	$ 425.44	$ 16.12	3.94%
4,500	$ 458.95	$ 476.89	$ 17.94	3.91%
5,000	$ 508.58	$ 528.34	$ 19.76	3.89%
10,000	$ 1,004.88	$ 1,042.86	$ 37.99	3.78%
20,000	$ 1,997.46	$ 2,071.90	$ 74.44	3.73%

[*227]
The following rates were used in the development of these bills:

Market Price Charge	$ 0.06701	per kWh
Market Price Adjustment	$ -	per kWh
Purchased Power Adjustment	$ (0.00225)	per kWh
Miscellaneous Charges	$ 0.00066	per kWh
SBC/RPS	$ 0.00116	per kWh
Revenue Tax Rate - Commodity	0.339%	

Revenue Tax Rate - Delivery	2.339%

Non-Demand Metered

Service Classification No. 2 - General Service

Energy kWh	Present Rates	Proposed Rates	Change ($)	Change (%)
-	$ 14.05	$ 16.05	$ 2.01	14.29%
12	$ 15.02	$ 17.05	$ 2.02	13.48%
25	$ 16.08	$ 18.12	$ 2.04	12.72%
50	$ 18.11	$ 20.19	$ 2.08	11.50%
75	$ 20.14	$ 22.26	$ 2.12	10.53%
100	$ 22.17	$ 24.32	$ 2.16	9.74%
132	$ 24.76	$ 26.97	$ 2.21	8.91%
150	$ 26.22	$ 28.46	$ 2.23	8.52%
175	$ 28.25	$ 30.53	$ 2.27	8.04%
200	$ 30.28	$ 32.59	$ 2.31	7.63%
500	$ 54.64	$ 57.40	$ 2.76	5.06%
750	$ 74.93	$ 78.07	$ 3.14	4.19%
1,000	$ 95.22	$ 98.74	$ 3.52	3.70%
2,500	$ 216.99	$ 222.78	$ 5.79	2.67%
5,000	$ 419.92	$ 429.51	$ 9.58	2.28%
10,000	$ 825.80	$ 842.96	$ 17.16	2.08%
20,000	$ 1,637.55	$ 1,669.86	$ 32.31	1.97%

The following rates were used in [*228] the development of these bills:

Market Price Charge	$ 0.06701	per kWh
Market Price Adjustment	$ -	per kWh
Purchased Power Adjustment	$ (0.00225)	per kWh
Miscellaneous Charges	$ 0.00066	per kWh
SBC/RPS	$ 0.00116	per kWh
Revenue Tax Rate - Commodity	$ 0.339%	
Revenue Tax Rate - Delivery	$ 0.339%	

Small General Demand Metered Service

Service Classification No. 2 - Secondary Customers

Demand kW	Energy kWh	Present Rates	Proposed Rates	Change ($)	Change (%)
7	2,500	$ 242.68	$ 249.59	$ 6.91	2.85%
10	2,500	$ 261.29	$ 269.49	$ 8.20	3.14%
17	2,500	$ 304.69	$ 315.92	$ 11.22	3.68%
14	5,000	$ 465.30	$ 475.60	$ 10.30	2.21%
20	5,000	$ 502.50	$ 515.40	$ 12.89	2.57%
33	5,000	$ 583.12	$ 601.62	$ 18.50	3.17%
29	10,000	$ 916.73	$ 934.26	$ 17.53	1.91%
40	10,000	$ 984.94	$ 1,007.21	$ 22.28	2.26%
67	10,000	$ 1,152.37	$ 1,186.29	$ 33.93	2.94%
57	20,000	$ 1,807.19	$ 1,838.30	$ 31.12	1.72%
80	20,000	$ 1,949.81	$ 1,990.85	$ 41.04	2.10%
133	20,000	$ 2,278.46	$ 2,342.37	$ 63.91	2.80%
90	50,000	$ 4,162.31	$ 4,212.18	$ 49.87	1.20%
115	50,000	$ 4,317.34	$ 4,377.99	$ 60.66	1.40%
230	50,000	$ 5,030.45	$ 5,140.73	$ 110.27	2.19%
175	100,000	$ 8,273.55	$ 8,367.62	$ 94.07	1.14%
230	100,000	$ 8,614.60	$ 8,732.40	$ 117.80	1.37%

Demand kW	Energy kWh	Present Rates	Proposed Rates	Change ($)	Change (%)
460	100,000	$ 10,040.84	$ 10,257.87	$ 217.04	2.16%
350	200,000	$ 16,527.03	$ 16,711.65	$ 184.63	1.12%
460	200,000	$ 17,209.14	$ 17,441.23	$ 232.09	1.35%
920	200,000	$ 20,061.61	$ 20,492.17	$ 430.56	2.15%
520	300,000	$ 24,749.50	$ 25,022.53	$ 273.03	1.10%
700	300,000	$ 25,865.68	$ 26,216.37	$ 350.69	1.36%
700	400,000	$ 33,033.99	$ 33,399.73	$ 365.74	1.11%
920	400,000	$ 34,398.21	$ 34,858.87	$ 460.66	1.34%
868	500,000	$ 41,244.06	$ 41,697.33	$ 453.28	1.10%

[*229]

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

Market Price Charge	$ 0.06701	per kWh
Market Price Adjustment	$ -	per kWh
Purchased Power Adjustment	$ (0.00225)	per kWh
Miscellaneous Charges	$ 0.00066	per kWh
SBC/RPS	$ 0.00116	per kWh
Revenue Tax Rate - Commodity	$ 0.339%	
Revenue Tax Rate - Delivery	$ 0.339%	

Small General Demand Metered Service

Service Classification No. 2 - Primary Customers

Demand kW	Energy kWh	Present Rates	Proposed Rates	Change ($)	Change (%)
7	2,500	$ 282.35	$ 294.72	$ 12.37	4.38%
10	2,500	$ 296.23	$ 309.50	$ 13.27	4.48%
17	2,500	$ 328.61	$ 343.99	$ 15.38	4.68%
14	5,000	$ 484.43	$ 499.13	$ 14.70	3.03%
20	5,000	$ 512.19	$ 528.69	$ 16.51	3.22%
33	5,000	$ 572.32	$ 592.74	$ 20.42	3.57%
29	10,000	$ 893.22	$ 912.88	$ 19.67	2.20%
40	10,000	$ 944.10	$ 967.08	$ 22.98	2.43%
67	10,000	$ 1,068.99	$ 1,100.10	$ 31.11	2.91%
57	20,000	$ 1,701.54	$ 1,730.54	$ 29.00	1.70%
80	20,000	$ 1,807.93	$ 1,843.85	$ 35.92	1.99%
133	20,000	$ 2,053.09	$ 2,104.97	$ 51.88	2.53%
90	50,000	$ 3,890.59	$ 3,932.23	$ 41.64	1.07%
115	50,000	$ 4,006.23	$ 4,055.40	$ 49.17	1.23%
230	50,000	$ 4,538.18	$ 4,621.97	$ 83.78	1.85%
175	100,000	$ 7,677.78	$ 7,749.52	$ 71.74	0.93%
230	100,000	$ 7,932.19	$ 8,020.49	$ 88.30	1.11%
460	100,000	$ 8,996.10	$ 9,153.63	$ 157.53	1.75%
350	200,000	$ 15,275.28	$ 15,408.74	$ 133.45	0.87%
460	200,000	$ 15,784.11	$ 15,950.67	$ 166.56	1.06%
920	200,000	$ 17,911.92	$ 18,216.96	$ 305.03	1.70%
520	300,000	$ 22,849.66	$ 23,043.32	$ 193.66	0.85%
700	300,000	$ 23,682.28	$ 23,930.12	$ 247.84	1.05%
700	400,000	$ 30,470.29	$ 30,727.17	$ 256.87	0.84%
920	400,000	$ 31,487.94	$ 31,811.04	$ 323.10	1.03%
868	500,000	$ 38,035.42	$ 38,351.89	$ 316.47	0.83%

[*230]

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

Market Price Charge	$ 0.06701	per kWh

Market Price Adjustment	$ -	per kWh
Purchased Power Adjustment	$ (0.00225)	per kWh
Miscellaneous Charges	$ 0.00066	per kWh
SBC/RPS	$ 0.00116	per kWh
Revenue Tax Rate - Commodity	0.339%	
Revenue Tax Rate - Delivery	0.339%	

ATTACHMENT IV

Appendix D, Schedule 1

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Gas Income Statements

($ 000)

	Rate Years Ending			
		6/30/07	**6/30/08**	**6/30/09**
Line No.		**(A)**	**(B)**	**(C)**
	Operating Revenues			
1	Gas Delivery Revenues - Before Increase	$ 42,041	$ 51,457	$ 59,008
2	Rate Increase	8,003	6,057	-
3	Interruptible & Sales to Generators	1,000	1,000	1,000
4	Other Operating Revenues	1,982	914	943
5	Total Operating Revenues	53,027	59,428	60,950
6	Operating Expenses			
7	Labor	9,523	9,820	10,101
8	Research and Development	299	304	306
9	Expenses Projected Based on Inflation	3,064	3,131	3,200
10	Miscellaneous General Expenses	462	470	479
11	Transportation - Depreciation	341	349	356
12	Fringe Benefits	1,369	1,403	1,442
13	Other Post Employee Benefits (OPEB)	1,943	1,943	1,943
14	Pension Plan	2,413	2,413	2,413
15	Environmental	64	65	67
16	Contract Rents	187	191	195
17	Uncollectible Accounts	462	531	545
18	Regulatory Commission Expenses	380	388	397
19	Data Processing Expense	527	539	550
20	Other Operating Insurance	214	219	224
21	Telephone	225	230	236
22	Legal Services	576	589	602
23	Special Services	324	331	338
24	Injuries and Damages	448	458	468
25	Powerful Opportunities Program	172	199	225
26	Expenses Allocated to Affiliates	(87)	(89)	(91)
27	MGP Remediation Cost Recovery	-	250	250
28	Recovery of Net Regulatory Assets	-	4,274	4,346
29	Competition Education Program	53	53	53
30	Productivity	(34)	(34)	(34)
31	Total Operating Expenses	22,925	28,026	28,611

	Rate Years Ending	6/30/07	6/30/08	6/30/09
Line No.		**(A)**	**(B)**	**(C)**
	Other Deductions			
32	Property Taxes	5,342	5,531	5,727
33	Revenue Taxes	1,022	1,244	1,288
34	Payroll Taxes	680	695	710
35	Other Taxes	173	177	181
36	Depreciation	6,478	6,335	6,192
37	Total Other Deductions	13,695	13,981	14,098
38	State Income Taxes	984	1,054	1,110
39	Federal Income Taxes	4,885	5,243	5,475
40	Total Income Taxes	5,869	6,296	6,585
41	Total Operating Revenue Deductions	42,489	48,304	49,294
42	Operating Income	10,538	11,124	11,657
43	Rate Base	$ 149,521	$ 156,889	$ 163,440
44	Rate of Return	7.05%	7.09%	7.13%

[*231]

Appendix D, Schedule 2

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Gas Rate Base

Gas			
Rate Years Ending	**6/30/07**	**6/30/08**	**6/30/09**
Book Cost of Utility Plant	$ 250,779	$ 265,176	$ 279,055
Less: Accumulated Provision for Depreciation and Amortization	(94,887)	(100,183)	(105,299)
Net Plant	155,892	164,993	173,756
Noninterest-Bearing Construction Work in Progress	9,930	10,207	10,319
Preliminary Survey & Investigation	0	0	0
Customer Advances for Undergrounding	(2)	(2)	(2)
Deferred Charges	4,382	4,247	3,877
Accumulated Deferred Federal Taxes	(24,504)	(26,326)	(28,221)
Accumulated Deferred State Taxes	(206)	(419)	(638)

Gas

Rate Years Ending

	6/30/07	**6/30/08**	**6/30/09**
Working Capital	6,569	6,729	6,889
Unadjusted Rate Base	152,061	159,429	165,980
Capitalization Adjustment to Rate Base	(2,540)	(2,540)	(2,540)
Total	$ 149,521	$ 156,889	$ 163.440

ATTACHMENT V

Appendix E

[SEE TABLE IN ORIGINAL]

[SEE TABLE IN ORIGINAL]

ATTACHMENT VI

Appendix F

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Summary of Proposed Monthly Gas Delivery Rates

		Current Rates	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
S.C. No. 1 & 12					
Billing Block 1	First 2 Ccf	$ 7.20	$ 14.00	$ 14.00	$ 14.00
Billing Block 2 per Ccf	Next 48 Ccf	$ 0.4250	$ 0.4620	$ 0.5284	$ 0.5284
Billing Block 3 per Ccf	Additional	$ 0.3028	$ 0.2892	$ 0.3300	$ 0.3300
S.C. No. 2, 6 & 13					
Billing Block 1	First 2 Ccf	$ 7.20	$ 20.00	$ 20.00	$ 20.00
Billing Block 2 per Ccf	Next 98 Ccf	$ 0.3307	$ 0.3505	$ 0.3843	$ 0.3843
Billing Block 3 per Ccf	Next 4900 Ccf	$ 0.2041	$ 0.2163	$ 0.2372	$ 0.2372
Billing Block 4 per Ccf	Additional	$ 0.1760	$ 0.1869	$ 0.2048	$ 0.2048
S.C. No. 11 Transmission					
Customer Charge		$ 317.00	$ 317.00	$ 317.00	$ 317.00
MDQ		$ 6.46	$ 6.46	$ 6.46	$ 6.46
S.C. No. 11 Distribution					
Customer Charge		$ 317.00	$ 317.00	$ 317.00	$ 317.00
MDQ		$ 11.76	$ 11.76	$ 11.76	$ 11.76
S.C. No. 11 DLM					
Customer Charge		$ -	$ 317.00	$ 317.00	$ 317.00
MDQ		$ -	$ 6.79	$ 6.79	$ 6.79

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Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

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	626,640	643,344	660,480
	Block 1 - Mcf - Not Billed	119,680	122,860	126,150
	Block 2 - Mcf	2,140,570	2,197,630	2,256,170
	Block 3 - Mcf	3,199,990	3,285,290	3,372,810
S.C. No. 1 & 12 Res. Non-Heat	Block 1 - Customer Months	117,720	115,260	112,848
	Block 1 - Mcf - Not Billed	19,960	19,510	19,130
	Block 2 - Mcf	128,490	125,830	123,180
	Block 3 - Mcf	52,010	50,930	49,850
S.C. No. 2, 6 & 13 Heat	Block 1 - Customer Months	110,616	114,600	118,716
	Block 1 - Mcf - Not Billed	17,290	17,880	18,500
	Block 2 - Mcf	611,690	632,790	654,600
	Block 3 - Mcf	3,728,300	3,856,360	3,988,670
	Block 4 - Mcf	1,011,750	1,046,450	1,082,270
S.C. No. 2, 6 & 13 Non-Heat	Block 1 - Customer Months	17,964	18,504	19,068
	Block 1 - Mcf - Not Billed	2,380	2,490	2,560
	Block 2 - Mcf	67,760	70,290	72,940
	Block 3 - Mcf	289,700	300,540	311,790
	Block 4 - Mcf	757,374	824,126	835,566
S.C. No. 11 Transmission	Customer Months	36	36	36
	MDQ	161,412	161,412	161,412
S.C. No. 11 Distribution	Customer Months	24	24	24
	MDQ	9,444	9,444	9,444
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	26,000	26,000	26,000

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Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Gas Commodity Related Merchant Function Charges

	Applicable to S. C. No.	MFC[A] $/ccf	MFC[B] $/ccf	MFC[T] $/ccf
MFC-1	1	0.00680	0.01390	0.02070
MFC-2	2	0.00213	0.00277	0.00490

Notes:

1. Customers taking commodity service from Central Hudson will be billed by Central Hudson for MFC[T], which is equal to the sum of MFC[A] and MFC[B].

2. MFC[A] will include the allocated portion of collection function costs and 50% of procurement-related call center function costs, plus administrative & general and rate base items associated with each of these items. Customers that choose to purchase their commodity service from an energy services company (ESCO) that is participating in Central Hudson's Purchase of Receivables (POR) Program will be billed by Central Hudson for MFC[A] only.

3. MFC[B] will include commodity purchasing function costs, allocated portions of advertising & promotions function costs and 50% of procurement-related call center function costs, plus administrative & general and rate base items associated with each of these items.

Central Hudson [*234] Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Comparison of Bills Under Present and Proposed Rates

P.S.C. No. 12 - Gas

Service Classification Nos. 1 & 12

Monthly Usage Ccf	Monthly Bill Present	Proposed	Monthly Bill Change in Amount	Increase
2	$ 9.16	$ 16.15	$ 6.98	76.20%
4	11.81	18.87	7.06	59.78%
6	14.45	21.58	7.13	49.37%
8	17.09	24.30	7.21	42.18%
10	19.74	27.02	7.29	36.92%
15	26.34	33.82	7.48	28.38%
20	32.95	40.62	7.67	23.26%
25	39.56	47.42	7.86	19.86%
30	46.17	54.21	8.05	17.43%
35	52.78	61.01	8.24	15.61%
40	59.38	67.81	8.43	14.19%
50	72.60	81.41	8.81	12.13%
60	84.56	93.23	8.67	10.25%
80	108.49	116.87	8.39	7.73%
100	132.41	140.52	8.11	6.12%
130	168.29	175.98	7.69	4.57%
170	216.14	223.27	7.13	3.30%
200	252.02	258.73	6.71	2.66%
300	371.64	376.95	5.31	1.43%

Monthly Usage Ccf	Monthly Bill Present	Monthly Bill Proposed	Change in Amount	Increase
1000	1,208.93	1,204.47	(4.46)	-0.37%
	Typical Annual Heating Customer @ 1100 Ccf Per Year			
	$ 1,454.23	$ 1,546.68	$ 92.45	6.36%

Revenue Tax Factor:	Delivery	0.02612
	Commodity	0.00612
Gas Supply Charge:		$ 0.8798

Central Hudson Gas & Electric Corporation [*235]

Cases 05-E-0934 & 05-G-0935

Comparison of Bills Under Present and Proposed Rates

P.S.C. No. 12 - Gas

Service Classification Nos. 2 & 13

Monthly Usage Ccf	Monthly Bill Present	Monthly Bill Proposed	Change in Amount	Increase
2	$ 9.01	$ 21.89	$ 12.88	142.86%
10	18.76	31.80	13.04	69.51%
30	43.12	56.55	13.44	31.16%
50	67.48	81.31	13.84	20.50%
100	128.37	143.21	14.83	11.55%
150	182.90	198.35	15.44	8.44%
200	237.43	253.49	16.06	6.76%
250	291.96	308.63	16.67	5.71%
300	346.49	363.78	17.29	4.99%
400	455.55	474.06	18.51	4.06%
500	564.60	584.35	19.74	3.50%
600	673.66	694.63	20.97	3.11%
800	891.78	915.20	23.42	2.63%
1000	1,109.89	1,135.77	25.88	2.33%
1500	1,655.18	1,687.19	32.02	1.93%
2000	2,200.47	2,238.62	38.15	1.73%
3000	3,291.04	3,341.47	50.43	1.53%
5000	5,472.19	5,547.17	74.98	1.37%
7500	8,127.94	8,230.34	102.40	1.26%
10000	10,783.69	10,913.51	129.81	1.20%
12000	12,908.30	13,060.05	151.75	1.18%
14000	15,032.90	15,206.58	173.68	1.16%
16000	17,157.50	17,353.12	195.62	1.14%
20000	21,406.71	21,646.19	239.49	1.12%
	Annual Heating Customer @ 5300 Ccf Per Year			
	$ 5,937.16	$ 6,161.32	$ 224.16	3.78%

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Revenue Tax Factor:	Delivery	0.00612
	Commodity	0.00612
Gas Supply Charge:		$ 0.8798

ATTACHMENT VII

Appendix G, Schedule 1

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Electric Deferred Items For Offset - Projected as of June 30, 2006

($ 000)

Electric Department	**Deferred Charge**	**Deferred Tax**	**Net**
Deferred Debits			
Pension Costs - Under/(Over) Collection	$ 29,616	($ 11,809)	$ 17,807
OPEB Costs - Excluding Medicare Subsidy - Under/(Over) Collection	11,113	(4,433)	6,680
Pension Reserve Carrying Charges	7,172	(2,860)	4,312
Stray Voltage Testing Costs	2,050	(818)	1,232
Carrying Charges on Stray Voltage Testing Costs	65	(24)	41
NYS Income Taxes (00-M-1556)	260	3,678	3,938
Research & Development Costs	369	(149)	220
Total Deferred Debits	$ 50,645	($ 16,415)	$ 34,230
Deferred Credits			
Proceeds from Sale of Clean Air Act Allowances	($ 13,576)	$ 5,414	($ 8,162)
Benefit Fund Principle & Carrying Charges (1)	(12,450)	4,450	(8,000)
Variable Rate Notes	(3,666)	1,461	(2,205)
NMP-2 Settlement Agreement Costs	(1,930)	775	(1,155)
Reliability Service Quality Penalty	(1,138)	454	(684)
OPEB Reserve Carrying Charges	(1,220)	487	(733)
Carrying Charges - Deferred NYS Taxes	(1,014)	404	(610)
Carrying Charges - CAA Allowance Proceeds	(724)	288	(436)
Carrying Charge on NMP-2 Settlement Agreement Costs	(490)	201	(289)
NYS Deferred Tax - Restate 8.50% & 8.00% Balances to 7.50%	0	(172)	(172)
Powerful Opportunity Costs	0	0	0
Total Deferred Credits	($ 36,208)	$ 13,762	($ 22,446)
Net Deferred Debit	14,437	(2,653)	11,784
Amount Recovered from Excess Depreciation Reserve	(14,437)	2,653	(11,784)

Electric Department	Deferred Charge	Deferred Tax	Net
Net Remaining Deferred Balance	$ 0	$ 0	$ 0

(1) Includes Shared Earnings deferred for Customer benefit of $ 22.3 million

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Appendix G, Schedule 2

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Gas Deferred Items For Offset - Projected as of June 30, 2006

($ 000)

Gas Department		Deferred Charge	Deferred Tax	Net
Deferred Debits				
Pension Costs - Under/(Over) Collection	a	$ 19,206	($ 7,658)	$ 11,548
Pension Reserve Carrying Charges	b	6,790	(2,708)	4,082
OPEB Costs - Excluding Medicare				
Subsidy - Under/(Over) Collection	a	6,179	(2,463)	3,716
Gas Earnings Restoration	b	1,272	(508)	764
NYS Income Taxes (00-M-1556)	b	87	426	513
Total Deferred Debits		$ 33,534	($ 12,911)	$ 20,623
Deferred Credits				
Gas Shared Earnings				
(Rate Years 1 through 3)	b	(1,486)	592	(894)
Variable Rate Notes	b	(1,149)	460	(689)
OPEB Reserve Carrying Charges	b	(502)	204	(298)
Research & Development Costs	b	(11)	6	(5)
Carrying Charges - Deferred NYS Taxes	b	(96)	39	(57)
NYS Deferred Tax - Restate				
8.50% & 8.00% Balances to 7.50%		0	(150)	(150)
Powerful Opportunity Costs	b	0	0	0
Total Deferred Credits		($ 3,244)	$ 1,151	($ 2,093)
Net Deferred Debit		$ 30,290	($ 11,760)	$ 18,530
Recovery of Gas Net Regulatory Asset				
Net Deferred Items Not				
Subject to Interest	a	$ 25,387	($ 10,123)	$ 15,264
Net Deferred Items				
Subject to Interest	b	4,903	(1,637)	3,266
		$ 30,290	($ 11,760)	$ 18,530

The non-interest bearing components ("a" references) of the gas net

Gas Department	Deferred Charge	Deferred Tax	Net
regulatory asset balance are amortized on a straight-line basis over 7 years beginning July 1, 2007, the start of RY2.	$ 25,387	/ 7 years =	$ 3,627
The interest bearing components ("b" references) of the gas net regulatory asset balance accrue interest during RY1 at the carrying charge rate. The balance at July 1, 2007, which includes interest accrued in RY1, is amortized over 7 years, on a levelized basis recognizing accrued interest on the unamortized balance at the carrying charge rate, beginning July 1, 2007, the start of RY2[1].	$ 4,903	over 7 years plus interest =	719
Total Annual Amortization of Net Gas Regulatory Asset			$ 4,346

1. The amount for RY2 shown on Appendix D, Schedule 1, Line 28 has been moderated to eliminate the need for a RY3 gas rate change.
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Appendix G, Schedule 3

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Deprecation Reserve Rate Moderator

($ 000)

Settlement Excess Electric Depreciation Reserve		$ 52,500
Recovery of Net Electric Regulatory Assets		
Net Regulatory Assets Remaining After Offset	$ 14,437	
Deferred Taxes on Above	(2,653)	11,784
Remaining Balance After Offset		40,716
Amounts Applied to Phase-in Electric Rate Increase		
Rate Year 1	(22,887)	
Rate Year 2	(11,840)	
	(34,727)	
	0.60125	(20,880)
Remaining Balance After Offset & Phase-In		$ 19,837
Pre-tax Equivalent		$ 32,992

ATTACHMENT VIII

Appendix H, Schedule 1

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Capital Structure and Allowed Rate of Return

($ 000)

Rate Year 1:	**Amount**	**Ratio**	**Cost**	**Weighted Cost**	**Pre-Tax Weighted Cost**
Long-Term Debt	$ 367,579	51.2%	4.99%	2.55%	2.55%
Customer Deposits	6,359	0.9%	3.00%	0.03%	0.03%
Preferred Stock	21,030	2.9%	5.04%	0.15%	0.25%
Common Equity	323,094	45.0%	9.60%	4.32%	7.18%
	$ 718,062	100.0%		7.05%	10.01%

Rate Year 2:	**Amount**	**Ratio**	**Cost**	**Weighted Cost**	**Pre-Tax Weighted Cost**
Long-Term Debt	$ 382,837	51.3%	5.07%	2.60%	2.60%
Customer Deposits	6,359	0.9%	3.00%	0.03%	0.03%
Preferred Stock	21,030	2.8%	5.04%	0.14%	0.24%
Common Equity	335,686	45.0%	9.60%	4.32%	7.19%
	$ 745,912	100.0%		7.09%	10.05%

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Rate Year 3:	**Amount**	**Ratio**	**Cost**	**Weighted Cost**	**Pre-Tax Weighted Cost**
Long-Term Debt	$ 411,042	51.6%	5.15%	2.66%	2.66%
Customer Deposits	6,359	0.8%	3.00%	0.02%	0.02%
Preferred Stock	21,030	2.6%	5.04%	0.13%	0.22%
Common Equity	358,658	45.0%	9.60%	4.32%	7.18%
	$ 797,089	100.0%		7.13%	10.09%

Appendix H, Schedule 2

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Electric and Gas Basis Point Values

Basis Point Values:

Electric	**RY1**	**RY2**	**RY2**
Rate Base ($ 000)	$ 544,007	$ 578,065	$ 615,375
x Equity Ratio	45%	45%	45%
Equity component of Rate Base ($ 000)	$ 244,803	$ 260,129	$ 276,919
x 1 BP	0.01%	0.01%	0.01%
After-tax value of 1 BP - whole dollars	$ 24,500	$ 26,000	$ 27,700
Pre-tax value of 1 BP - whole dollars	$ 40,700	$ 43,200	$ 46,100

Basis Point Values:

Gas	**RY1**	**RY2**	**RY2**
Rate Base ($ 000)	$ 149,521	$ 156,889	$ 163,440
x Equity Ratio	45%	45%	45%
Equity component of Rate Base ($ 000)	$ 67,284	$ 70,600	$ 73,548
x 1 BP	0.01%	0.01%	0.01%

Basis Point Values:

Gas	RY1	RY2	RY2
After-tax value of 1 BP - whole dollars	$ 6,700	$ 7,100	$ 7,400
Pre-tax value of 1 BP - whole dollars	$ 11,100	$ 11,800	$ 12,300

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Appendix H, Schedule 3

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Cases 05-E-0934 & 05-G-0935

LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST

FOR THE TWELVE MONTHS ENDING JUNE 30, 2007

($ 000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2006 (3)	Charges During Rate Year (4)
Long Term Debt				
Outstanding Issues				
NYSERDA Series A	August 1, 2027	5.45	33,400	-
NYSERDA Var Rate	August 1, 2028	3.10	41,150	-
NYSERDA Var Rate	August 1, 2028	3.02	41,000	-
Polution Control Note	December 1, 2028	3.00	16,700	-
NYSERDA Var Rate	July 1, 2034	3.38	33,700	-
	March 28, 2007	5.87	33,000	(33,000)
	January 15, 2009	6.00	20,000	-
	September 23, 2010	4.33	24,000	-
	March 28, 2012	6.64	36,000	-
	February 27, 2014	4.73	7,000	-
	November 5, 2014	4.80	7,000	-
	December 1, 2035	5.84	24,000	-
	October 1, 2016	6.25	-	11,169
	February 1, 2017	6.25	-	39,000
	November 4, 2019	5.05	27,000	-
Average Long Term Debt Outstanding				
Interest Charges for the Rate Year				
Plus: Amortization of Debt Discount and Expense				
Less: Amortization of Premium on Debt				
Total Cost of Debt				
Amount				
% of Average Long Term Debt Outstanding				

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	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt			
Outstanding Issues			
NYSERDA Series A	12	33,400	1,820
NYSERDA Var Rate	12	41,150	1,276
NYSERDA Var Rate	12	41,000	1,238
Polution Control Note	12	16,700	501
NYSERDA Var Rate	12	33,700	1,139
	9	24,750	1,453
	12	20,000	1,200
	12	24,000	1,039
	12	36,000	2,390
	12	7,000	331
	12	7,000	336
	12	24,000	1,402
	9	8,377	524
	5	16,250	1,016
	12	27,000	1,364
Average Long Term Debt Outstanding		$ 360,327	
Interest Charges for the Rate Year			$ 17,028
Plus: Amortization of Debt Discount and Expense			973
Less: Amortization of Premium on Debt			3
Total Cost of Debt			
Amount			$ 17,998
% of Average Long Term Debt Outstanding			4.99%

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Cases 05-E-0934 & 05-G-0935

LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST

FOR THE TWELVE MONTHS ENDING JUNE 30, 2008

($ 000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2007 (3)	Charges During Rate Year (4)
Long Term Debt				
Outstanding Issues				
NYSERDA Series A	August 1, 2027	5.45	33,400	-
NYSERDA Var Rate	August 1, 2028	3.10	41,150	-

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2007 (3)	Charges During Rate Year (4)
NYSERDA Var Rate	August 1, 2028	3.02	41,000	-
Polution Control Note	December 1, 2028	3.00	16,700	-
NYSERDA Var Rate	July 1, 2034	3.38	33,700	-
	January 15, 2009	6.00	20,000	-
	September 23, 2010	4.33	24,000	-
	March 28, 2012	6.64	36,000	-
	February 27, 2014	4.73	7,000	-
	November 5, 2014	4.80	7,000	-
	December 1, 2035	5.84	24,000	-
	October 1, 2016	6.25	11,169	-
	February 1, 2017	6.25	39,000	-
	January 1, 2018	6.25	-	28,515
	November 4, 2019	5.05	27,000	-

Average Long Term Debt Outstanding

Interest Charges for the Rate Year

Plus: Amortization of Debt Discount and Expense
Less: Amortization of Premium on Debt

Total Cost of Debt
Amount

% of Average Long Term Debt Outstanding
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	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt			
Outstanding Issues			
NYSERDA Series A	12	33,400	1,820
NYSERDA Var Rate	12	41,150	1,276
NYSERDA Var Rate	12	41,000	1,238
Polution Control Note	12	16,700	501
NYSERDA Var Rate	12	33,700	1,139
	12	20,000	1,200
	12	24,000	1,039
	12	36,000	2,390
	12	7,000	331
	12	7,000	336
	12	24,000	1,402
	12	11,169	698
	12	39,000	2,438
	6	14,258	891
	12	27,000	1,364

	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Average Long Term Debt Outstanding		$ 375,377	
Interest Charges for the Rate Year			$ 18,063
Plus: Amortization of Debt Discount and Expense			959
Less: Amortization of Premium on Debt			3
Total Cost of Debt Amount			$ 19,019
% of Average Long Term Debt Outstanding			5.07%

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

Cases 05-E-0934 & 05-G-0935

LONG TERM DEBT - AVERAGE CAPITALIZATION AND COST

FOR THE TWELVE MONTHS ENDING JUNE 30, 2009

($ 000)

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2008 (3)	Charges During Rate Year (4)
Long Term Debt				
Outstanding Issues				
NYSERDA Series A	August 1, 2027	5.45	33,400	-
NYSERDA Var Rate	August 1, 2028	3.10	41,150	-
NYSERDA Var Rate	August 1, 2028	3.02	41,000	-
Polution Control Note	December 1, 2028	3.00	16,700	-
NYSERDA Var Rate	July 1, 2034	3.38	33,700	-
	January 15, 2009	6.00	20,000	(20,000)
	September 23, 2010	4.33	24,000	-
	March 28, 2012	6.64	36,000	-
	February 27, 2014	4.73	7,000	-
	November 5, 2014	4.80	7,000	-
	December 1, 2035	5.84	24,000	-
	October 1, 2016	6.25	11,169	-
	February 1, 2017	6.25	39,000	-
	January 1, 2018	6.25	28,515	-
	July 1, 2018	6.25	14,000	-
	April 1, 2019	6.25	-	34,380
	November 4, 2019	5.05	27,000	-

	Maturity Date (1)	Interest Rate % (2)	Principal Amount Outstanding 6/30/2008 (3)	Charges During Rate Year (4)
Average Long Term Debt Outstanding				
Interest Charges for the Rate Year				
Plus: Amortization of Debt Discount and Expense				
Less: Amortization of Premium on Debt				
Total Cost of Debt				
Amount				
% of Average Long Term Debt Outstanding				

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	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
Long Term Debt			
Outstanding Issues			
NYSERDA Series A	12	33,400	1,820
NYSERDA Var Rate	12	41,150	.1,276
NYSERDA Var Rate	12	41,000	1,238
Polution Control Note	12	16,700	501
NYSERDA Var Rate	12	33,700	1,139
	7	10,833	650
	12	24,000	1,039
	12	36,000	2,390
	12	7,000	331
	12	7,000	336
	12	24,000	1,402
	12	11,169	698
	12	39,000	2,438
	12	28,515	1,782
	12	14,000	875
	3	8,595	537
	12	27,000	1,364
Average Long Term Debt Outstanding		$ 403,062	
Interest Charges for the Rate Year			$ 19,816
Plus: Amortization of Debt Discount and Expense			944
Less: Amortization of Premium on Debt			3
Total Cost of Debt			
Amount			$ 20,757

	Months Outstanding (5)	Average Amount Outstanding During Rate Year (6)	Interest Expense During Rate Year (7)
% of Average Long Term Debt Outstanding			5.15%

ATTACHMENT IX

Appendix I, Schedule 1

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Deferral Items

($ 000)

		ELECTRIC OPERATIONS			GAS OPERATIONS		
Rate Allowance Items:	**Method**	**RY1**	**RY2**	**RY3**	**RY1**	**RY2**	**RY3**
Asbestos Litigation	B	$ 0	$ 0	$ 0	$ 0	0	$ 0
Competition Education Program	C	$ 298	$ 298	$ 298	$ 53	53	$ 53
Gas Balancing Software	B	$ 0	$ 0	$ 0	$ 0	0	$ 0
MGP Remediation	A	$ 0	$ 1,400	$ 1,400	$ 0	250	$ 250
OPEB	A	$ 8,382	$ 8,382	$ 8,382	$ 1,943	1943	$ 1,943
Pension Plan	A	$ 10,568	$ 10,568	$ 10,568	$ 2,413	2413	$ 2,413
Powerful Opportunities Program	B	$ 976	$ 1,125	$ 1,275	$ 172	199	$ 225
Property Taxes	D	$ 19,758	$ 20,460	$ 21,183	$ 5,342	5531	$ 5,727
Research & Development	B	$ 1,846	$ 1,857	$ 1,860	$ 299	304	$ 306
Stray Voltage Testing	B	$ 2,200	$ 2,250	$ 2,300	n/a	n/a	n/a
Real-Time Gas Meters 04-G-0463	A	n/a	n/a	n/a	$ 0	$ 0	$ 0

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Capital & Expense Expenditure Targets (cumulative totals through Rate Year 3):

Category	**Type**	**Target**	**Method**
Electric	Cap	$ 158,078	C
Gas	Cap	$ 27,495	C
Common	Cap	$ 21,693	C
Steel/Cast Iron Replacement	Cap	$ 15,750	C
Transmission ROW Maintenance	Exp	$ 6,723	C
East Fishkill Substation	Cap & Exp		A

Cost of Capital:

Variable Rate Debt Interest Rate (all rate years):	**Target**	**Method**
$ 41.150 Million Issue	3.10%	B

Variable Rate Debt Interest Rate (all rate years):	**Target**	**Method**
$ 41.000 Million Issue	3.02%	B
$ 33.700 Million Issue	3.38%	B

Method of Deferral:

A - Deferral of costs over/under rate allowance, no limitation

B - Deferral of costs over/under rate allowance subject to limitation

C - Deferral of costs less than rate allowance

D - Shared deferral of costs over/under rate allowance subject to limitation

Appendix I, Schedule 2

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Revenue Matching Factors

	Rate Year # 1	**Rate Year # 2**	**Rate Year # 3**
ELECTRIC:			
Research & Development:			
Rate Allowance ($ 000)	$ 1,846	$ 1,857	$ 1,860
SC 1, 2, 3, 5, 6, 8, 9 & 13			
Sales (mWh)	5,756,150	5,870,650	5,966,350
Revenue Matching Factor - $/kWh	$ 0.000321	$ 0.000316	$ 0.000312
Pension Plan:			
Rate Allowance ($ 000)	$ 10,568	$ 10,568	$ 10,568
SC 1, 2, 3, 5, 6, 8, 9 & 13			
Sales (mWh)	5,756,150	5,870,650	5,966,350
Revenue Matching Factor - $/kWh	$ 0.001836	$ 0.001800	$ 0.001771
OPEB's:			
Rate Allowance ($ 000)	$ 8,382	$ 8,382	$ 8,382
SC 1, 2, 3, 5, 6, 8, 9 & 13			
Sales (mWh)	5,756,150	5,870,650	5,966,350
Revenue Matching Factor - $/kWh	$ 0.001456	$ 0.001428	$ 0.001405
GAS:			
Research & Development:			
Rate Allowance ($ 000)	$ 299	$ 304	$ 306
SC 1, 2, 6, 12 & 13 Sales (Mcf)	12,146,946	12,553,010	12,914,218
Revenue Matching Factor - $/Mcf	$ 0.024615	$ 0.024217	$ 0.023695
Pension Plan:			
Rate Allowance ($ 000)	$ 2,413	$ 2,413	$ 2,413
SC1, 2, 6, 12 & 13 Sales (Mcf)	12,146,946	12,553,010	12,914,218
Revenue Matching Factor - $/Mcf	$ 0.198651	$ 0.192225	$ 0.186848
OPEB's:			
Rate Allowance ($ 000)	$ 1,943	$ 1,943	$ 1,943
SC 1, 2, 6, 12 & 13 Sales (Mcf)	12,146,946	12,553,010	12,914,218

	Rate Year # 1	Rate Year # 2	Rate Year # 3
ELECTRIC:			
Revenue Matching Factor - $/Mcf	$ 0.159958	$ 0.154784	$ 0.150454

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ATTACHMENT X

Appendix J

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

DEPRECIATION RATES

PSC ACCT NO	PLANT ACCOUNT	Average Service Life	Net Salvage	Annual Deprec Rate
	ELECTRIC PLANT IN SERVICE			
	HYDRO PLANT			
331.00	STRUCTURES AND IMPROVEMENT	60	(50)	2.50
332.00	RESERVOIRS, DAMS AND WATERWAYS	75	(60)	2.13
333.00	TURBINES AND GENERATORS	60	(60)	2.67
334.10	ACCESSORY ELECTRIC EQUIPMENT	55	(60)	2.91
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	40	(40)	3.50
	OTHER PRODUCTION PLANT			
341.00	STRUCTURES AND IMPROVEMENTS	27	(5)	3.89
342.00	FUEL HOLDERS, PRODUCERS & ACCESSORIES	27	(5)	3.89
343.00	PRIME MOVERS	27	(5)	3.89
344.00	GENERATORS	27	(5)	3.89
345.00	ACCESSORY ELECTRIC EQUIPMENT	27	(5)	3.89
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	27	(5)	3.89
	TRANSMISSION PLANT			
350.11	LAND AND LAND RIGHTS-LINES	85	10	1.06
352.00	STRUCTURES AND IMPROVEMENTS	65	(40)	2.15
353.11-20	STATION EQUIPMENT-IN USE	55	(20)	2.18
353.12	SUPERVISORY EQUIPMENT-IN USE	28	(10)	3.93
354.00	TOWERS AND FIXTURES	65	(30)	2.00
355.00	POLES AND FIXTURES	55	(50)	2.73
355.15	POLES AND FIXTURES-345KV LINE	55	(50)	2.73
356.10	OVERHEAD CONDUCTORS AND DEVICES	60	(25)	2.08
356.15	OVERHEAD CONDUCTORS AND DEVICES-345KV LINE	60	(35)	2.25
356.20	CLEARING	60	(35)	2.25
356.25	CLEARING-345KV LINE	60	(35)	2.25
357.00	UNDERGROUND CONDUIT	40	(5)	2.63
358.00	UNDERGROUND CONDUCTORS AND DEVICES	40	(20)	3.00
	DISTRIBUTION PLANT			
360.11	LAND AND LAND RIGHTS-OVERHEAD LINES	60	10	1.50
360.22	LAND AND LAND RIGHTS-UNDERGROUND	60	10	1.50
361.00	STRUCTURES AND IMPROVEMENTS	80	(25)	1.56
362.11-20	STATION EQUIPMENT-IN USE	52	(20)	2.31
362.12	SUPERVISORY EQUIPMENT-IN USE	30	(10)	3.67
364.00	POLES, TOWERS AND FIXTURES	55	(25)	2.27

PSC ACCT NO	PLANT ACCOUNT	Average Service Life	Net Salvage	Annual Deprec Rate
365.00	OVERHEAD CONDUCTORS AND DEVICES	60	(30)	2.17
366.00	UNDERGROUND CONDUIT	65	(25)	1.92
367.00	UNDERGROUND CONDUCTOR AND DEVICES	55	(10)	2.00
368.00	TRANSFORMERS	43	(10)	2.56
369.10	SERVICES OVERHEAD	52	(75)	3.37
369.20	SERVICES UNDERGROUND	52	(25)	2.40
370.00	METERS	32	0	3.13
371.00	INSTALLATIONS ON CUSTOMER PREMISES	20	(15)	5.75
372.00	LEASED PROPERTY ON CUSTOMER PREMISES	11	0	9.09
373.00	STREET LIGHTING	30	(25)	4.17
390.00	STRUCTURES AND IMPROVEMENTS	40	(30)	3.25
	GAS PLANT IN SERVICE			
	MANUFACTURING GAS PLANT - PROPANE			
305.00	STRUCTURES AND IMPROVEMENTS	75	(10)	1.47
311.00	LIQUIFIED PETROLEUM GAS EQUIPMENT	60	(45)	2.42
320.10	OTHER EQUIPMENT	25	0	4.00
	TRANSMISSION PLANT			
365.11	LAND	0	0	-
365.20	LAND RIGHTS	70	0	1.43
365.50	LAND RIGHTS-IROQUOIS	70	0	1.43
366.20	STRUCTURES AND IMPROVEMENTS	45	(40)	3.11
366.50	STRUCTURES AND IMPROVEMENTS-REG STATION IROQUC	45	(40)	3.11
367.00	MAINS	68	(40)	2.06
367.50	MAINS - IROQUOIS	68	(40)	2.06
369.11	REGULATING STATION EQUIPMENT	35	(30)	3.71
369.12	REGULATING STATION EQUIPMENT-SUPERVISORY	18	(20)	6.67
369.51	REGULATING STATION EQUIPMENT-IROQUOIS	35	(30)	3.71
369.52	REGULATING STATION EQUIPMENT-SUPERVISORY IROQUC	18	(20)	6.67
	DISTRIBUTION PLANT			
374.11	LAND AND LAND RIGHTS-MAINS	70	0	1.43
375.00	STRUCTURES AND IMPROVEMENTS	60	(30)	2.17
376.00	MAINS	85	(60)	1.88
378.11	REGULATING STATION EQUIPMENT	35	(35)	3.86
378.12	REGULATING STATION EQUIPMENT-SUPERVISORY	30	(15)	3.83
380.00	SERVICES	70	(60)	2.29
381.00	METERS	32	(10)	3.44
382.00	METER INSTALLATIONS	40	(15)	2.88
383.00	HOUSE REGULATORS	55	0	1.82
384.00	HOUSE REGULATOR INSTALLATION	45	(20)	2.67
385.00	INDUSTRIAL REGULATING STATION EQUIPMENT	55	(30)	2.36
385.10	INDUSTRIAL REGULATING STATION REMOTE METERING	55	(30)	2.36
	COMMON PLANT IN SERVICE			
390.00	STRUCTURES AND IMPROVEMENTS	50	(50)	3.00
390.10	STRUCTURES AND IMPROVEMENTS-LEASED PROPERTY	50	(50)	3.00

PSC ACCT NO	PLANT ACCOUNT	Average Service Life	Net Salvage	Annual Deprec Rate
391.11	OFFICE EQUIPMENT-EDP-GENERAL	8	0	12.50
391.12	OFFICE EQUIPMENT-EDP-SYSTEM OPERATION	12	0	8.33
391.21	OFFICE EQUIPMENT-DATA HANDLING	20	0	5.00
391.22	OFFICE FURNITURE AND EQUIPMENT-OTHER	20	0	5.00
392.10	TRANSPORTATION EQUIPMENT	8	10	11.25
392.20	TRANSPORTATION EQUIPMENT-GAS	8	10	11.25
392.40	TRANSPORTATION EQUIPMENT-COMMON	8	10	11.25
393.00	STORES EQUIPMENT	35	0	2.86
393.20	STORES EQUIPMENT - FORKLIFTS	35	0	2.86
394.10	GARAGE & REPAIR EQUIPMENT	30	0	3.33
394.20	SHOP EQUIPMENT	30	0	3.33
394.30	TOOLS AND WORK EQUIPMENT	30	0	3.33
395.10	LABORATORY EQUIPMENT	35	0	2.86
395.20	LABORATORY EQUIPMENT-R&D	35	0	2.86
396.10	POWER OPERATED EQUIP-ELECTRIC	12	15	7.08
396.20	POWER OPERATED EQUIPMENT-GAS	12	15	7.08
396.40	POWER OPERATED EQUIPMENT-COMMON	12	15	7.08
397.10	COMMUNICATION EQUIPMENT-RADIO	20	0	5.00
397.20	COMMUNICATION EQUIPMENT-TELEPHONE	10	0	10.00
398.00	MISCELLANEOUS EQUIPMENT	30	0	3.33

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PSC ACCT NO	PLANT ACCOUNT	Survivor Curve	Allocation of Excess Reserve
	ELECTRIC PLANT IN SERVICE		
	HYDRO PLANT		
331.00	STRUCTURES AND IMPROVEMENT	R3	(59,000)
332.00	RESERVOIRS, DAMS AND WATERWAYS	L5	(230,700)
333.00	TURBINES AND GENERATORS	R4	(290,000)
334.10	ACCESSORY ELECTRIC EQUIPMENT	R1.5	40,400
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	S2.5	(50,900)
	OTHER PRODUCTION PLANT		
341.00	STRUCTURES AND IMPROVEMENTS	R5	(62,300)
342.00	FUEL HOLDERS, PRODUCERS & ACCESSORIES	R5	(102,700)
343.00	PRIME MOVERS	R5	(361,500)
344.00	GENERATORS	R5	(198,200)
345.00	ACCESSORY ELECTRIC EQUIPMENT	R5	92,200
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	R5	(1,100)

PSC ACCT NO	PLANT ACCOUNT	Survivor Curve	Allocation of Excess Reserve
	TRANSMISSION PLANT		
350.11	LAND AND LAND RIGHTS-LINES	R4	(68,000)
352.00	STRUCTURES AND IMPROVEMENTS	R3	145,000
353.11-20	STATION EQUIPMENT-IN USE	R1	(7,919,600)
353.12	SUPERVISORY EQUIPMENT -IN USE	S1	(775,300)
354.00	TOWERS AND FIXTURES	R3	(490,400)
355.00	POLES AND FIXTURES	R3	1,049,200
355.15	POLES AND FIXTURES-345KV LINE	R3	353,500
356.10	OVERHEAD CONDUCTORS AND DEVICES	R2	(526,100)
356.15	OVERHEAD CONDUCTORS AND DEVICES-345KV LINE	R2	(81,300)
356.20	CLEARING	R2	(33,100)
356.25	CLEARING-345KV LINE	R2	(9,500)
357.00	UNDERGROUND CONDUIT	L0.5	(7,400)
358.00	UNDERGROUND CONDUCTORS AND DEVICES	R3	(1,094,500)
	DISTRIBUTION PLANT		
360.11	LAND AND LAND RIGHTS-OVERHEAD LINES	S4	(39,900)
360.22	LAND AND LAND RIGHTS-UNDERGROUND	S4	(200)
361.00	STRUCTURES AND IMPROVEMENTS	R3	(108,400)
362.11-20	STATION EQUIPMENT-IN USE	R1.5	397,000
362.12	SUPERVISORY EQUIPMENT-IN USE	R2	(437,400)
364.00	POLES, TOWERS AND FIXTURES	01	(11,591,300)
365.00	OVERHEAD CONDUCTORS AND DEVICES	R1	(9,817,300)
366.00	UNDERGROUND CONDUIT	R3	(10,600)
367.00	UNDERGROUND CONDUCTOR AND DEVICES	R2.5	(2,330,500)
368.00	TRANSFORMERS	L1	(6,657,700)
369.10	SERVICES OVERHEAD	R1.5	(5,497,100)

PSC ACCT NO	PLANT ACCOUNT	Survivor Curve	Allocation of Excess Reserve
369.20	SERVICES UNDERGROUND	R1.5	(517,600)
370.00	METERS	R1.5	(589,000)
371.00	INSTALLATIONS ON CUSTOMER PREMISES	R0.5	(878,500)
372.00	LEASED PROPERTY ON CUSTOMER PREMISES	L2	(456,000)
373.00	STREET LIGHTING	L0	(3,136,000)
390.00	STRUCTURES AND IMPROVEMENTS	R1.5	(148,200)
			(52,500,000)
	GAS PLANT IN SERVICE		
	MANUFACTURING GAS PLANT - PROPANE		
305.00	STRUCTURES AND IMPROVEMENTS	Undetermined	
311.00	LIQUIFIED PETROLEUM GAS EQUIPMENT	Undetermined	
320.10	OTHER EQUIPMENT	S3	
	TRANSMISSION PLANT		
365.11	LAND		
365.20	LAND RIGHTS	S4	
365.50	LAND RIGHTS-IROQUOIS	S4	
366.20	STRUCTURES AND IMPROVEMENTS	R3	
366.50	STRUCTURES AND IMPROVEMENTS-REG STATION IROQUC	R3	
367.00	MAINS	Undetermined	
367.50	MAINS - IROQUOIS	Undetermined	
369.11	REGULATING STATION EQUIPMENT	Undetermined	
369.12	REGULATING STATION EQUIPMENT-SUPERVISORY	S0.5	
369.51	REGULATING STATION EQUIPMENT-IROQUOIS	Undetermined	
369.52	REGULATING STATION EQUIPMENT-SUPERVISORY IROQUC	S0.5	
	DISTRIBUTION PLANT		
374.11	LAND AND LAND RIGHTS-MAINS	R3	
375.00	STRUCTURES AND IMPROVEMENTS	Undetermined	
376.00	MAINS	R3	
378.11	REGULATING STATION	Undetermined	

PSC ACCT NO	PLANT ACCOUNT	Survivor Curve	Allocation of Excess Reserve
	EQUIPMENT		
378.12	REGULATING STATION EQUIPMENT-SUPERVISORY	Undetermined	
380.00	SERVICES	R2	
381.00	METERS	R1.5	
382.00	METER INSTALLATIONS	Undetermined	
383.00	HOUSE REGULATORS	Undetermined	
384.00	HOUSE REGULATOR INSTALLATION	L5	
385.00	INDUSTRIAL REGULATING STATION EQUIPMENT	Undetermined	
385.10	INDUSTRIAL REGULATING STATION REMOTE METERING	Undetermined	
	COMMON PLANT IN SERVICE		
390.00	STRUCTURES AND IMPROVEMENTS	L0	
390.10	STRUCTURES AND IMPROVEMENTS-LEASED PROPERTY	L0	
391.11	OFFICE EQUIPMENT-EDP-GENERAL	L3	
391.12	OFFICE EQUIPMENT -EDP-SYSTEM OPERATION	L2	
391.21	OFFICE EQUIPMENT-DATA HANDLING	L0	
391.22	OFFICE FURNITURE AND EQUIPMENT-OTHER	L0	
392.10	TRANSPORTATION EQUIPMENT	L3	
392.20	TRANSPORTATION EQUIPMENT-GAS	L3	
392.40	TRANSPORTATION EQUIPMENT-COMMON	L3	
393.00	STORES EQUIPMENT	L2	
393.20	STORES EQUIPMENT - FORKLIFTS	L2	
394.10	GARAGE & REPAIR EQUIPMENT	R1.5	
394.20	SHOP EQUIPMENT	R1.5	
394.30	TOOLS AND WORK EQUIPMENT	R1.5	
395.10	LABORATORY EQUIPMENT	L1	
395.20	LABORATORY EQUIPMENT-R&D	L1	
396.10	POWER OPERATED	L3	

PSC ACCT NO	PLANT ACCOUNT	Survivor Curve	Allocation of Excess Reserve
	EQUIP-ELECTRIC		
396.20	POWER OPERATED EQUIPMENT-GAS	L3	
396.40	POWER OPERATED EQUIPMENT-COMMON	L3	
397.10	COMMUNICATION EQUIPMENT-RADIO	R2.5	
397.20	COMMUNICATION EQUIPMENT-TELEPHONE	L3	
398.00	MISCELLANEOUS EQUIPMENT	R0.5	

[*247]

ATTACHMENT XI

Appendix K

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Gas Balancing Methodology Applicable to S.C. 9 and 11

Monthly Balanced Service

Peak Requirements		Mcf	% Mcf	Allocation of Costs	Normalized Throughput (Mcf)	Balancing Svc Chg ($/Mcf)
S.C. No. 9	(a)	420	1.22%	$ 63,071	797,600	$ 0.0791
S.C. No. 11 - Trans. & Dist.	(a)	614	1.78%	$ 92,235	1,992,800	$ 0.0463
S.C. No. 11 -DLM	(a)	1,436	4.17%	$ 215,468	847,692	$ 0.2542
Other Classes		31,995	92.83%	$ 4,802,322	12,228,595	$ 0.3927
Total		34,465	100.00%	$ 5,173,095	15,866,687	

Daily Balanced Service

Peak Consumption	Mcf	2% Peak Consumption	% of Total Peaking Requirements	Balancing Svc Chg ($/Mcf)
S.C. No. 9	2,968	59	14.13%	$ 0.0112
S.C. No. 11 - Trans. & Dist.	10,860	217	35.35%	$ 0.0164
S.C. No. 11 -DLM	5,741	115	8.00%	$ 0.0203
Other Classes	107,142	2,143	6.70%	$ 0.0263
	126,711			

(a)

	Total Extreme Day Demand (Mcf)	Total Extreme Day Demand w/LAUF 2.50%	Total Extreme Day Delivery (Mcf)	Deficiency (Mcf)	% of Demand
S.C. No. 9	2,968	3,042	2,622	420	14%
S.C. No. 11 -					

		Total Extreme Day Demand (Mcf)	Total Extreme Day Demand w/LAUF 2.50%	Total Extreme Day Delivery (Mcf)	Deficiency (Mcf)	% of Demand
Trans. & Dist.		10,860	11,132	10,517	614	6%
S.C. No. 11 - DLM		5,741	5,885	4,449	1,436	25%
	Total	16,601	17,016	14,966	2,050	

[*248]
Note:

The above amounts are based on actual data as of February 1, 2006.

ATTACHMENT XII

Appendix L

Central Hudson Gas & Electric Corporation

Cases 05-E-0934 & 05-G-0935

Detailed CSI Margin of Error Calculation

For purposes of supplementing the Customer Satisfaction Index (CSI) value which is currently provided by Central Hudson at the end of the year, and for purposes of determining if that CSI value has changed in a significant manner from the prior year's CSI level, Central Hudson will provide the following margin of error (MOE) calculations.

1. To provide an estimate of the 95% confidence interval regarding the responses to each of the eight individual survey questions whose results are combined to create the overall CSI, Central Hudson will perform the following MOE calculation for each question.

[SEE EQUATION IN ORIGINAL]

Where the subscript ″Qi″ signifies each of the eight individual satisfaction survey questions, ″p″ is the proportion of customers surveyed who answered ″Very Satisfied″ or ″Satisfied″ on each individual question and ″n″ the base number of customers who responded to that individual question in that year.

2. To provide a reasonable approximation [*249] of the MOE for the overall CSI level for each year, (which is a weighted combination of the proportions of ″Very Satisfied″ or ″Satisfied″ customer responses to the eight individual questions), Central Hudson will provide the following calculation

[SEE EQUATION IN ORIGINAL]

Where the CSI level for the year will be treated as signifying the proportion, ″p″ of customers who are satisfied overall (as if each surveyed customer were asked a single question, ″are you satisfied overall″), and ″n″ will signify the maximum number of annual customer survey responses received on any of the questions in that year.

ATTACHMENT XIII

ATTACHMENT 2

SUBJECT: Filings by CENTRAL HUDSON GAS & ELECTRIC CORPORATION

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

First Revised Leaf No. 218.2

Second Revised Leaf No. 231
Fourth Revised Leaves Nos. 106, 218.1, 219
Fifth Revised Leaves Nos. 165, 185, 205.1, 210, 217, 222
Sixth Revised Leaves Nos. 105, 220, 246
Seventh Revised Leaves Nos. 104, 169, 205, 218
Supplements Nos. 30, 31, 32

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

First Revised Leaf No. 181
Third Revised Leaves Nos. 68, 71, 72, 158
Fourth Revised Leaves Nos. 151, 152, 188, 193
Fifth **[*250]** Revised Leaf No. 149
Sixth Revised Leaves Nos. 186, 191
Eighth Revised Leaf No. 159
Supplements Nos. 20, 22, 23