STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 08-E-0887 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service

CASE 08-G-0888 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service

CASE 09-M-0004 - Petition of Central Hudson Gas & Electric Corporation for Authorization to Defer Ice Storm Recovery Costs

ORDER ADOPTING RECOMMENDED DECISION WITH MODIFICATIONS

(Issued and Effective June 22, 2009)

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At a session of the Public Service Commission held in the City of Albany on June 18, 2009

COMMISSIONERS PRESENT:

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

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BY THE COMMISSION:

I. INTRODUCTION

This proceeding was initiated in response to Central Hudson Gas & Electric Corporation's (Central Hudson's or Company's) filing on July 31, 2008 of tariff amendments reflecting an increase in rates and charges of approximately $35.4 million, or 16.3%, for electric delivery service, and

$14.7 million, or 28.2%, for gas delivery service.[1] The filing called for the new rates to take effect on July 1, 2009, along with a one-year Electric Bill Credit (EBC) through which the Company would refund an estimated $21.2 million owed to its electric customers to mitigate the first-year impact of the rate increase.[2]

The Staff of the Department of Public Service (Staff) proposed numerous adjustments to the Company's proposal, having the aggregate effect of reducing the Company's requested increases for electric and gas delivery service to $16.1 million and $6.4 million, respectively. Staff opposed the use of an EBC, but recommended that some of the funds being held by the Company for the benefit of ratepayers be used to offset various non-recurring expenditures.

Central Hudson and Staff both also proposed the adoption of revenue decoupling mechanisms (RDM) as directed by our *Order Requiring Proposals for Revenue Decoupling Mechanisms* issued April 20, 2007.[3] The proposals differed in detail but shared the objective of removing disincentives to utility support of our efforts to promote energy efficiency and conservation.

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[1] Notice of the Company's filings was published in the New York State Register on November 12, 2008 (SAPA Nos. 08-E-0887SA1 and 08-G-0888SA1). No comments other than those discussed herein were received.

[2] The effective date of the Company's filing was suspended by the Commission through June 27, 2009, by Order Suspending Major Rate Filing issued on August 25, 2008, and a Further Suspension of Rate Filings issued on December 11, 2008.

[3] Case 03-E-0640, et al., Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation, Order Requiring Proposals For Revenue Decoupling Mechanisms (issued April 20, 2007).

Following a pre-hearing conference in September 2008, written testimony was filed in December by Staff and the U.S. Department of Defense and other Federal Executive Agencies (DOD/FEA) on behalf of the U. S. Military Academy at West Point (West Point). Four days of hearings were held from January 12 through January 15, 2009, with cross-examination conducted by representatives of the Company, Staff, DOD/FEA, the Consumer Protection Board, Multiple Intervenors (MI) and the Small Customer Marketer Coalition (SCMC).[4]

Following the hearings, initial briefs were filed on February 17, 2009, by the Company, Staff, DOD/FEA, MI and SCMC. The same parties filed reply briefs on March 11, 2009, as did the National Energy Marketers Association and the New York State Energy Marketers Coalition.

A Recommended Decision (RD) was issued by the judges on April 10, 2009. It reflected a revenue requirement of $33.1 million for electric service and $12.5 million for gas service. Despite adopting a number of adjustments proposed by the parties that reduced revenue requirement, as filed by the Company, the net effect of the recommendations was to lower the Company's requested increases for electric and gas service by less than $2 million and $3 million, respectively, due to the impact of the recently enacted Temporary State Energy and Utility Service Conservation Assessment which greatly increased the Company’s obligation under Public Service Law Section 18-a (PSL §18-a).

Exceptions to the RD were filed by the Company, Staff, DOD/FEA and SCMC on April 30, 2009, and the same parties submitted briefs opposing exceptions on May 15, 2009.

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[4] The record created includes 2,424 pages of transcript and 170 exhibits.

Public Comment

During this proceeding we have received comments from over 120 residents, businesses and public officials from Central Hudson's service territory. Nearly 100 contacted us by e-mail or through our website. Another 16 appeared in person and spoke at public statement hearings conducted on March 12, 2009, at the Poughkeepsie, New York, Municipal Building. Commissioner Acampora participated in the afternoon session of those hearings.

All of the individuals from whom we heard oppose any increase in rates for Central Hudson. Retired people and others living on fixed incomes expressed concern that rising utility costs for necessities such as heat and electricity were a severe burden. Many working people also complained that reduced employment opportunities and financial pressure on their employers to hold down wages and salaries put them in no better position to absorb increased rates than their retired counterparts.

At the public statement hearings, we also heard from representatives of the Town of Poughkeepsie and the Town of Marlborough, a member of the Dutchess County Legislature and the administrator of the Poughkeepsie water treatment facility. All expressed concern about the impact of a rate increase on governmental expenses and the pressure it would create for additional taxes at a time when their constituents can least afford them.

Subsequently, we have received letters in opposition to the rate increase from Dutchess and Greene Counties, the Towns of Esopus, Jewett and Wappinger, the City of Beacon, and the Villages of Athens and Red Hook. The letters included resolutions expressing opposition to the rate increase adopted by the Dutchess County Legislature, the Greene County

Legislature, the Beacon City Council and the Town Board of Wappinger.

The Orange County Partnership and the Rockland Economic Development Corporation also submitted letters. These did not address the proposed rate increases, but expressed continued support for funding by Central Hudson of the Hudson Valley Economic Development Corporation.

II. DISCUSSION

Having carefully reviewed the evidence; the arguments of the active parties; comments by interested public officials, organizations, and members of the public; and the recommendations of Advisory Staff, we adopt the recommendations of the RD with certain modifications which we identify in our analysis of contested issues set forth below.

Based on those recommendations, as modified, we authorize Central Hudson to increase its delivery rates for the year beginning July 1, 2009, by $38.0 million for electric service and $13.6 million for gas service. The revenue requirement schedules are contained in Appendix II and Appendix III. Although we have removed the effect of the increase in the PSL § 18-a assessment from base delivery rates by instituting a separate surcharge, the authorized increase remains very close to that recommended in the RD. This is due to cost increases driven primarily by steep declines in the value of investments supporting the Company's pension and post-employment benefits programs.

In order to mitigate the bill impact of the rate increase for electric service, we are also instituting an EBC. This credit on customers' bills will offset $20 million of the delivery rate increase during the rate year, and could ultimately provide $36 million of benefits to ratepayers over the next three years.

In addition, we approve the implementation by Central Hudson of Revenue Decoupling Mechanisms for both gas and electric operations.

Our analysis of the parties' principal exceptions to the RD follows.

A. ECONOMIC CONSIDERATIONS – AUSTERITY

Citing significant weakness in the financial markets, and rising unemployment, as well as the record created at the Public Statement hearings and through other public inputs, the RD recommended three adjustments to the Company's requests in an attempt to create an appropriate, austerity-based rate allowance. The three issues on which the RD concluded that austerity concerns were paramount were: employee count (the RD recommended 830; Central Hudson requests 846); variable pay programs; and gas institutional advertising. These adjustments totaled $3.8 million on electric and $900,000 for gas.

The Company objects to the consideration of macroeconomic conditions which are not reflected in the record. It also excepts to the RD’s finding that the amounts requested in these categories are reasonable, while simultaneously refusing to recommend them based on austerity concerns. Staff agrees with the RD’s recommendations, but argues that the right result (i.e., the revenue requirement reduction) was reached for the wrong reason (i.e., austerity), inasmuch as the Company’s proposed expenditures in these three categories could not be justified, in Staff’s view, through a cost-of-service analysis.

Discussion - We agree with the RD’s conclusion that rate allowances cannot be made in a vacuum. Central Hudson’s exceptions to considering general economic information, fail to recognize that these concerns have been documented on an almost daily basis in publicly-available economic reports, were also raised by MI, and were repeatedly reflected in public comments received at the Public Statement Hearings and in writing. Our consideration of these issues is not only record based, but, in fact, we would be remiss in our obligation to the public interest were we to fail to take notice of the magnitude and depth of the current recession. Accordingly, the Company's exceptions are denied.

We are well aware of the 1980 Statement of Policy Concerning Evidence of Economic Impact in Rate Cases (Evidence of Economic Impact Policy Statement or EI Policy), and the austerity adjustment we will implement here is not inconsistent with that policy. Indeed, the EI Policy Statement explicitly recognizes that "[e]vidence of economic distress in a utility's service territory might be cited to support arguments for limiting a particular expense allowance to the low end of a range of reasonableness, where such a range exists."[5] Thus, the Statement not only acknowledges that adjustments of this type may be taken, it also provides guidance describing the supporting evidence that might be offered in these circumstances, and how such evidence might be employed to evaluate "the consequences of rate determinations for the economic circumstances of a utility's territory."[6] Plainly, the EI Policy Statement, while critical of the information provided in earlier cases, does not preclude the use of the evidence before us today (testimony of parties, public hearing statements, publicly available statistics documenting the health of the State's economy) to establish the basis for the austerity adjustment we are taking here.

When, as the RD, public comments and public information readily at hand demonstrate, our economy is experiencing extraordinary challenges and many consumers are

[5] EEI Policy Statement at 5.

[6] EEI Policy Statement at 2.

taking any measures available to adjust their household budgets to reductions in available income, our rate decisions and, in particular, our decisions to increase rates should take account of the macroeconomic environment as it exists at the time of our decision. In a recent Consolidated Edison Company of New York, Inc. (Con Edison) order[7] we stated:

> Expenditures that are reasonable during average or good economic times are not necessarily reasonable when economic conditions are extremely poor. When consumers are experiencing the extraordinary harsh economic realities we see today, a certain measure of frugality is properly expected from utilities and a reprioritizing of expenditures may be needed.

As this excerpt from our recent decision makes clear, an austerity adjustment responsive to the current macroeconomic conditions is not simply a reduction in the utility’s revenue requirement that translates into an immediate and negative impact on the Company’s rate of return. Rather, the need for austerity and its implementation calls for adjustments in the Company’s priorities such that expenses, otherwise reasonable, are foregone or deferred. Once these short-term expense reductions are made, the resulting austerity adjustment translates these savings to rate savings for customers. Because there are actual savings associated with the austerity adjustments, there is no impact on the utility’s earned rate of return on equity in the rate year.

While we agree with the RD’s recognition that an austerity adjustment is appropriate under the current circumstances, we will not adopt the specific approach to austerity taken in the RD. With respect to the three areas

[7] Case 08-E-0539, Proceeding on Motion of the Commission as to the Rates, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Establishing Rates For Electric Service (Con Edison Order) (issued April 24, 2009), p. 342.

highlighted in the RD for the austerity adjustment, we agree with Staff that reductions in those areas should be evaluated just as any other proposed cost-of-service adjustment to the Company's revenue requirement, and we provide our evaluations on those items in the body of this order.[8]

Accordingly, our approach to austerity will not single out a disallowance for any particular expense. Instead, in order to allow the Company greater flexibility to manage its resources, we will impute an austerity adjustment and leave the Company free to choose its own strategies for the achievement of the corresponding short-term expense reductions. This imputation, while consistent with the approach taken in the Con Edison case[9], is based upon facts and circumstances specific to Central Hudson.

Central Hudson was required by our May 15, 2009, notice in the generic austerity case[10] to provide a description of the measures it has already taken for austerity purposes and to describe any cost control measures it may undertake in the coming year. We have received the Company's filing (June 15 Report) and it is consistent with much information that is already on the record. More specifically, because of constraints outside of its control, the Company has, over the past three years, successfully developed and implemented several significant measures to restrain expenditures. While some of these items may be viewed as temporary austerity measures, others represent more permanent solutions addressing the structural causes of certain costs.

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[8] Rate allowances for head count and variable pay are discussed below.

[9] Con Edison Order, pp.341-344.

[10] Case 09-M-0435, Proceeding on Motion of the Commission Regarding the Development of Utility Austerity Programs, Notice Requiring the Filing of Utility Austerity Plans (May 15, 2009).

The June 15 Report in the generic austerity case also describes several cost-control measures Central Hudson may undertake in the coming year. These include the deferral of certain capital expenditures, reductions in research and development expenses, caps on certain executive salaries, and reductions in other operation and maintenance expenditures.[11] At this stage, while we can comment on certain aspects of the Company's June 15 Report, we are not able to fully evaluate the nature and scope of all of the Company's specific pro-forma measures. Nevertheless, we recognize Central Hudson's overall filing as a good faith effort to respond to the need for significant cost controls and austerity measures and we commend the Company for its prompt and complete response.

In light of our specific discussion of austerity in this case, and of the Company's efforts through this filing to meet the need for an austerity program, we will address the Company's June 15 Report filing in this proceeding. We expect the Company to supplement the June 15 filing with the additional information which we describe below as soon as possible.

Using the size of the adjustment specified in the Con Edison case as a starting point, and considering the unique circumstances of this Company, we conclude that the austerity adjustment goal for Central Hudson in this case should be in the amount of $2.4 million for electric operations and $0.6 million for gas operations. These amounts represent approximately 1.8% of the Company's non-fuel operation and maintenance expenses for electric and gas operations, respectively, and as such represent half the percentage than we applied in Con Edison. We will

[11] The Company also notes that to contain costs in recent years it was able to maintain its operations with a headcount of 825. While we have allowed a headcount of 840 in our rate determination herein, the Company may wish to consider extending the lower headcount, through attrition and fewer new hires, as an austerity measure until economic conditions improve.

measure the success of Central Hudson's austerity program against this lower percentage because of the record evidence and information in the June 15 Report indicating that the Company has already taken significant steps to reduce expenses through both austerity like measures and more permanent cost control solutions.

Our approach to the austerity adjustment and to the underlying expense reductions is one which recognizes that the best efforts implementation of the adjustment will identify expenses which, when foregone in the short term, may impose costs on ratepayers in the future. The Company's strategy for implementation of the adjustment should take care that these future costs are not disproportionate to the short-term savings provided to ratepayers though the adjustment. In addition, we expect that any austerity savings taken by the Company will not result in a direct impairment of the Company's programs to provide safe and adequate service.[12]

To assure these considerations are appropriately considered in the Company's plans, we direct Central Hudson to identify as promptly as possible the capital and expense reductions which it will be using to implement the austerity program and the impacts, if any, on service quality which may result from these reductions. In addition, the Company should identify and quantify future costs or increases in the Company's revenue requirement in later periods which may result from the capital and expense reductions which it is taking in the present rate year. Finally, the Company should identify each capital and expense reduction that it considered, but decided not to

[12] In this vein, we note that our preliminary review of the Company's June 15 Report indicates that its proposals regarding tree-trimming and stray-voltage inspections do not appear consistent with this standard and, as such, do not appear to be in the public interest.

include, as part of its austerity program and the reasons why the proposed reduction was not included.

Consistent with the implementation of the austerity goal specified in the recent Con Edison case, we recognize that the Company's best efforts may not realize the full amount of the austerity adjustment taken in this order. Accordingly, we will allow the Company to petition at the end of the rate year for a deferral corresponding to that amount of the austerity-related expense reductions which, despite the Company's best efforts, has not been realized. Following an evaluation of whether the Company used best efforts to achieve the full $2.4 million electric and $0.6 million gas savings reflected in rates, we would make a decision as to the amount of deferral, if any, to allow. This approach allows the Company the flexibility to manage its own resources in light of our current austere environment. It also helps to assure that the size of the adjustment, when implemented, corresponds to the size of the short-term savings the Company, using best efforts, will actually realize.

We fully expect the Company to use its best efforts to achieve the entire imputed revenue requirement reductions. Nevertheless, as we previously noted, the circumstances in this case do not offer the same breadth of opportunity for savings as we recognized in our Con Edison decision. Accordingly, in this case, we will place no minimum on the amount of austerity savings that must be achieved by the Company to qualify for deferral treatment. The Company should understand that it will have to carry its burden in establishing that despite its best efforts, cost cuts could not be achieved to make the full $2.4 million electric and $0.6 million gas revenue requirement reductions. However, with this demonstration, we recognize that up to the full amount of the austerity adjustment may become a deferral that the Company may seek to recover in its next rate case.

The June 15 Report and the additional information described above to supplement the June 15 Report will be evaluated and addressed as part of the compliance process for this order. If Staff and the Company, after evaluating the comments, if any, from other parties, agree that the measures identified by the Company will implement an austerity program in a form and an amount consistent with this order, Staff shall file with the Secretary on notice to all parties, its statement reflecting such agreement. If Staff and the Company cannot reach such an agreement, Staff shall, on notice to all parties, forward its recommendations to the Commission for the resolution of such dispute.

B. OPERATING REVENUES

1. Sales Forecasts

Staff takes exception to the RD's recommendation that the degree day inputs to the models used for forecasting sales should be derived from Central Hudson's monthly regression analysis rather than the 30-year averages on which Staff's forecasts were based. It argues that the linear trend lines generated from the aggregated annual numbers presented in Exhibit 85, which the RD found persuasive, are not the same as the monthly trends generated by Central Hudson's forecasting methodology. Staff says that Exhibit 91 shows the Company's numbers to be much less persuasive. Staff also reiterates its argument that the trend toward warmer weather remains weak and does not justify a change in forecasting methodology. It acknowledges that the Energy Information Administration of the U. S. Department of Energy (EIA) has shifted to a 10-year average for forecasting purposes, but says that shift does not validate Central Hudson's much different forecasting methodology.

In response, Central Hudson explains that Exhibit 85 does, in fact, reflect the degree day data it used by for its forecast. It says the RD was correct in concluding that the Company’s method better reflects recent degree day trends.

Discussion - In order to establish reasonable rates for Central Hudson, we have to forecast the total volume of electricity and gas that the Company can be expected to deliver during the rate year. Because those deliveries are heavily influenced by weather, the models we use must incorporate some estimate of the heating and cooling degree days that the service territory is likely to experience.

As the RD noted, we are not in the weather forecasting business, and cannot predict the actual weather for the rate year any better than the National Weather Service. Our objective, rather, is to choose degree day inputs for the forecasting models that are not inherently biased and are, therefore, likely to provide a reasonable projection of what sales in a “normal” year should look like.

The RD concluded that the 30-year average of historic degree day experience that we have customarily relied on no longer appears to satisfy this objective. It found that compared to actual experience over the 15 years ending 2007, the 30-year average overstated heating degree days (and understated cooling degree days) about two-thirds of the time, while both the Company’s methodology and the 10-year average now used by EIA showed no such bias.

We agree with the RD that a change is appropriate given recent experience, but we disagree with its selection of Central Hudson’s approach. As Staff pointed out, the 30-year average has historically served us well and has had the advantage of providing a simple, easily applied rule based on readily available data. Any change in the way we obtain the degree day inputs for our forecasting models should retain that simplicity.

Therefore, consistent with the approach taken by the EIA, we will adopt the most recent 10-year averages for purposes of providing heating and cooling degree-day inputs to the sales forecasts in this case. Furthermore, we expect these averages to be utilized for forecasting purposes in future rate filings.

2. Finance Charge Revenue

Central Hudson states that the calculation of an increase in finance charge revenues resulting from an authorized rate increase should be based on the cash increase in rates, that is, the portion of revenue requirement not funded from deferral accounts. The clarification is appropriate and is granted.

3. Update

Staff argues in its Brief Opposing Exceptions that Central Hudson's revision of its sales forecasts went beyond the application of revised values of forecast drivers to equations already on the record. It says the Company impermissibly re-estimated its forecasting equations and added or dropped variables. It recommends that the previously agreed-upon customer count be retained with updates allowed for April 2009 macroeconomic data and for the Company's projection of EEPS-related sales reductions.

Discussion – We adopt Staff's position. The RD's call for an update of the sales forecasts concurrent with the filing of the Company's Brief on Exceptions was not an authorization for wholesale revision of the equations themselves. The RD also authorized an update reflecting the impact of EEPS, and Staff acknowledges that the Company's estimate is consistent with its own.

C. OPERATING EXPENSES

1. Directors and Officers Liability (D&O) Insurance

The RD found that the overall level of D&O insurance coverage was appropriate and recommended that the full cost of the premium be allowed in rates. Staff does not disagree with the finding as to the level of coverage, but takes exception to the requirement that ratepayers bear the entire expense. It points to our Con Edison Order in which we found that this insurance coverage benefits both ratepayers and shareholders, and it argues that the 50-50 sharing of cost responsibility we ordered there should be adopted here.

The Company responds that no evidence was presented in this case to support a split of responsibility for premiums that the RD found were reasonably incurred business expenses.

Discussion - The Company’s argument misses the point. We acknowledged in our Con Edison Order that there is:

> no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders.[13]

In other words, we adopted the 50-50 sharing for Con Edison precisely because there was no empirical basis for determining the relative value of the benefits of this type of insurance to ratepayers and shareholders.

We have the same situation in this case, and we adopt the same resolution. Accordingly, Staff’s exception is granted, and we direct that one-half the cost of the premiums for D&O liability insurance be excluded from rates.

2. Labor

a. Employee Count

The RD found the Company's requested employee level of 846 to be reasonable, but recommended against an increase above

[13] Con Edison Order, pp. 90-91.

the historic level of 830 due to economic and austerity considerations as discussed above. The Company excepts to the refusal to allow costs for a “reasonable” number of employees. Staff agrees with the result, but argues that its adjustment be adopted without relying on austerity

Discussion - The Company's most recent updates reflect an employee count of 840. In our view, allowing this updated actual number of employees provides the Company a reasonable allowance for employee costs for the rate year before considering the poor economic climate. In addition, this employee level represents a compromise between the litigated positions of Staff and the Company. Further, allowing the actual, current employee level may present further opportunities for austerity savings. Accordingly, the Company's exceptions are granted to the extent of allowing 840 employees without austerity.

b. Variable Pay

The RD recommended that a rate allowance for the cost of Central Hudson's variable compensation programs be disallowed. It concluded that in the current difficult economic circumstances the cost of this program could not be considered a reasonable and necessary business expense.

Staff takes exception not to the RD's recommendation, but to its reasoning. It points to information included in Exhibit 144 which it says demonstrates that the metrics of the plans favor shareholders over ratepayers. Staff also argues that the Company has made no showing that the programs generate savings for ratepayers commensurate with their cost.

Central Hudson opposes disallowance of this expense on the austerity grounds found by the RD, and argues that if the variable compensation program were viewed in a normal context, its cost would be included in rates. It says that proper rate-setting balances the interests of ratepayers and shareholders, and that the standard suggested by Staff is too one-sided.

Discussion - Central Hudson has three incentive compensation plans. The first, an executive plan covering 12 top officials of the holding Company and the utility represents approximately 56% of the incentive pay for the rate year. The second, called a Performance Incentive Plan represents about 20% of the projected incentive pay expense and covers the general body of management employees, approximately one-third of the total work force. The third plan provides incentive compensation for 16 top managers and makes up 24% of the cost of the incentive pay programs.

Exhibit 144, cited by Staff, includes excerpts from Company documents which show that the primary target for each of the variable compensation plans relates to the reduction of operating expenses. We have previously stated that when the goals of an incentive plan are designed to reduce costs, and those cost reductions are not reflected in revenue requirement, the result is a windfall for shareholders at ratepayer expense.[14] Customers pay for the effort required to achieve benefits that flow through to the Company's bottom line.

We reiterated this concern in our recent Con Edison Order, in which we endeavored to make it very clear that:

> [Our] policy that such [variable compensation] plans must be self-supporting through productivity savings or financed by shareholders applies to any incentive plans that include financial parameters.[15]

We agree with Staff that such a showing has not been made by Central Hudson in this case. Accordingly, we clarify

[14] Case 90-G-0734, et al., Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service, Opinion 91-16 (issued July 19, 1991), p. 9.

[15] Con Edison Order, p. 53.

that our adoption of the RD's recommendation is based on our evaluation of the merits of the case presented by the parties, and not current economic circumstances.[16]

c. Update

In its Brief Opposing Exceptions, Staff states that Central Hudson updated the historic test year from March 31, 2008, to March 31, 2009. It says no such update was agreed to or authorized by the RD.

Discussion – No justification for this otherwise unauthorized update has been presented. Updated figures for this expense category will reflect the use of the original historic test year as the starting point.

3. MGP Expense

Central Hudson requested a rate allowance of approximately $8.0 million, as updated, for the cost of site investigation and remediation associated with former manufactured gas plants (MGP expense). No party contested the importance of the Company's pursuit of this environmental clean-up effort, or the need to ensure that Central Hudson is compensated for costs reasonably incurred in the process. Staff, however, contended that there was considerable uncertainty as to the actual outlay that would be required during the rate year. It proposed that the allowance be set at the level of the average expenditures of $2.8 million incurred by the Company over an historic three-year period, and that the electric component of any excess costs actually incurred during the rate year be offset against the existing net regulatory liability carried on the Company’s balance sheet.

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[16] As noted by Staff in its Brief Opposing Exceptions, the premium pay percentage applied in calculating labor expense for semi-monthly employees should not be applied to the variable pay which we have excluded.

The RD adopted Staff's proposal. Central Hudson excepts, arguing that the RD recognized that MGP expenditures would likely exceed the historic average, and that it should have been given at least a $5 million rate allowance, rather than a balance sheet offset.

Discussion - As noted in the RD, 92% of the MGP expense anticipated by the Company is associated with a single site located in Newburgh. The use of accumulated funds held for the benefit of ratepayers, and subject to Commission disposition, is entirely appropriate for the type of non-recurring, project-specific expenditures characteristic of MGP site remediation efforts. This approach moderates the required rate allowance, which may persist well beyond the completion of the project, while assuring that the utility is fully compensated. The Company's exception is denied.

4. Other Environmental Expense

The RD noted that the requested increase in the rate allowance for this expense category (in excess of inflation) was ostensibly based on the need to fund certain specific projects identified by the Company’s Director of Environmental Services. What those projects were, and why they were needed in the rate year, were never explained, according to the RD. Apparently, that information was shared among the parties in discovery, but was not offered in evidence by the Company. As a result, the RD concluded that there was no articulated support for recommending any increase in environmental expense beyond Staff's proposed escalation for inflation.

Central Hudson takes exception to this conclusion arguing that Staff never presented any evidence that the projections of the Company's environmental director were in error. It also contends that Staff made improper adjustments or ignored relevant data in calculating the three-year average it used to normalize the test year expense, and that its use of an historical average was inappropriate because the annual numbers showed an increasing cost trend. Finally, the Company asserts that it was unfair for the RD to give Staff an opportunity to clarify its position on storm restoration expense without allowing Central Hudson to provide more information on its environmental expense proposal. Therefore, it attaches its responses to Staff information requests to its Brief on Exceptions.

Staff responds that the fundamental purpose of a normalizing adjustment is to ensure that the base for forecasting rate year expense reflects expected expenditures and is not distorted by costs that are unusual. It adds that the data pointed to by the Company as evidence of an increasing cost trend actually reflects MGP expenditures, which are not included in the separate environmental expense account.

Discussion - Staff had no obligation to present a case refuting the sufficiency or validity of proposals the Company itself chose not to offer. No information concerning the projects proposed by the Company's Director of Environmental Services was available for the Recommended Decision. Further, the information clearly could have been submitted well in advance of the RD, as the attachments to the Company’s brief establishes. Under the circumstances, we are not obliged to consider this late filed evidentiary proffer, and, in the exercise of our discretion, it will not be considered in this proceeding. The Company's exception is denied.

5. Regulatory Commission Expense

The recent amendment of PSL §18-a, substantially increased the assessments payable by all utilities. We addressed the recovery of this additional expense for the first time in our Con Edison Order, which was issued two weeks after the RD in this case. Subsequently, we instituted a proceeding to consider the matter on a generic basis.[17]

Discussion - In the generic proceeding regarding PSL §18-a, we are issuing a ruling concurrently with the Order in this rate case adopting a surcharge to recover this expense in a manner similar to the method approved for Con Edison. Given the many issues involved in the generic proceeding, we will let its implementation establish a surcharge for Central Hudson. For the General Assessment designed to recover the Department of Public Service's costs, we will allow in base rates the most recent estimate available from Staff.

6. Right-of-Way Maintenance-Distribution Expense

According to Staff, Central Hudson included a new amount for right-of-way maintenance-distribution expense in updates submitted with its Brief on Exceptions. Staff contends that the update was not authorized by the RD and should be rejected.

Discussion – Staff is incorrect. The number included in the income statements submitted by Central Hudson with its Brief on Exceptions is not an update. It is the same amount that the Company presented in its direct testimony, as corrected on the record at the hearing. No party raised any issue concerning this requested rate allowance in its trial briefs, and there was no reason for it to be addressed in the RD. Staff's belated objection is untimely and is denied.

7. Storm Restoration Expense

The parties agreed that a rate allowance for the cost of restoration of service from storm-related outages should be based on a three-year average of actual expenses incurred, and

[17] Case 09-M-0311, Implementation of Chapter 59 of the Laws of 2009 Establishing a Temporary Annual Assessment Pursuant to PSL 18-a (6), Notice Requesting Comments (issued April 28, 2009).

that the average should be updated at the time of the Company's filing of its Brief on Exceptions. They disagreed, however, as to what should be included in the average. Staff argued that "anomalies" should be excluded. The Company found that standard to be unfairly vague.

The RD expressed concern with the subjective nature of Staff's proposed adjustment, but also recognized that inclusion of a truly anomalous event could unreasonably inflate the rate allowance. Consequently, it authorized Staff to explain in its Brief Opposing Exceptions what costs it would propose to remove from the average and why. The Company took exception to this provision on the grounds that Staff had not previously been able to articulate a standard for identifying anomalies, and that Central Hudson would not have a chance to respond.

In its Brief Opposing Exceptions, Staff proposed to exclude only one storm event from the average, a December 11, 2008, ice storm. It also reported that it would support the Company's request in Case 09-M-0004 for deferral of the costs associated with that storm.[18] A stipulation embodying that support and requesting that we grant the deferral petition was subsequently submitted, and we will address it separately below.

Discussion - The stipulation submitted by Staff and the Company did not explicitly resolve the issue of an appropriate rate allowance for storm restoration expense. To the contrary, it expressly provided that neither party was required by the agreement to abandon any position taken on the issue in this case.

Whether or not any actual dispute remains, however, we find that the use of a three-year average excluding the ice storm of December 11, 2008, is appropriate.

[18] Case 09-M-0004, Petition of Central Hudson Gas & Electric Corporation to Defer Ice Storm Recovery Costs.

Inclusion of particular storm costs in the average used for establishing the rate allowance for restoration expense is an implicit statement that the utility is expected to fund recovery related to storms of that type and magnitude from the amount provided in rates. Approval of a petition for deferral of recovery costs, on the other hand, is an acknowledgement that costs of that magnitude were not contemplated when rates were set. Either funding method, inclusion in the rate allowance or deferral accounting, will enable the utility to recover its costs, but the two methods cannot coincide. Therefore, it was appropriate to exclude the cost of the 2008 ice storm, for which we will authorize deferral, from calculation of the allowance in this case. Central Hudson's exceptions are denied.

8. Stray Voltage Expense

The RD recommended that the rate allowance for stray voltage expense include an amount estimated by Central Hudson for incremental costs associated with expanded requirements imposed by our December 15, 2008, Order Adopting Changes to Electric Safety Standards,[19] but reduced the amount by one-half of the adjustment proposed by Staff to reflect the fact that the Company's estimates have historically been overstated. Given the uncertainty of this approximation, the RD also recommended continuing the Company's existing authorization to use deferral accounting for this expense until Central Hudson completes one full cycle of stray voltage testing under the new rules.

Staff excepts, arguing that deferral accounting should be handled on a petition basis as under the original stray

[19] Case 04-M-0159, et al., Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems, Order Adopting Changes to Electric Safety Standards, (issued December 15, 2008) (Electric Safety Standards Order).

voltage testing order, is not appropriate for a one-year rate case, and is not necessary because there is now an expense history for this function on which to base a reasonable forecast. Staff also contends that the basis for allowing only one-half of its recommended adjustment is not clear.

Discussion - As noted, deferral accounting for this expense is currently approved for Central Hudson. The question is whether to continue it. Given the uncertainty associated with the new requirements, it is reasonable to do so for one testing cycle, after which better estimates should be possible. Reduction of the Company’s request by one-half of Staff's proposed adjustment was a compromise between the reality that the new requirements will increase costs, and the likelihood that Central Hudson's estimates of those increases will prove to be high. Staff’s exception regarding deferral is denied.

9. Transmission Sag Mitigation Program - Expense Component

A study conducted by Central Hudson in 2006 determined that a number of the Company's transmission circuits do not meet National Electrical Safety Code clearance requirements for pedestrian paths, roadways and other facilities. Severe problems will require the replacement of poles and towers with higher structures. Less extreme discrepancies can be corrected by re-tensioning lines. Central Hudson included a rate year request of $1.1 million for expenses related to re-tensioning, based on a projected cost of $3.3 million over three years.

No party questions the importance of the Company's undertaking this safety-related program or the overall cost estimate. Staff, however, takes exception to the RD's recommendation that Central Hudson be permitted to charge a fixed $1.1 million per year for re-tensioning expense against available credits. It contends that this approach will not provide adequate incentives for cost control, and recommends instead that the annual charge allowed be equal to the lesser of the estimated re-tensioning related costs or the actual expense incurred.

Discussion - Staff's exception is denied. We do not consider such a one-way true-up mechanism to be necessary for this expense. The transmission sag mitigation program is a discrete, multi-year project that we expect the Company to complete. The total estimate for the expense portion of the cost of this project, $3.3 million, is undisputed, and the RD recommended, consistent with Staff’s position, that the Company be allowed to fund it from available net credits rather than an allowance in rates. Cost control is provided by putting a $3.3 million cap on the total amount the Company is authorized to charge against those credits. Beyond that amount, Central Hudson will have to obtain Commission approval for a deferral or an additional rate allowance in some future case. If the Company under spends the allowance, a portion of the net credits will continue to be held for ratepayer benefit.

10. Uncollectible Bill Expense

The RD recommended that the rate allowance for this expense be based on the most recent data available prior to the issuance of our order, but denied the Company's request for authority to defer and reconcile excess expenditures. It noted that the Commission was considering the impact of growth in this expense category on a generic basis in a separate proceeding; that declining commodity prices should help moderate the problem; and that the update authorized should provide the Company with a reasonable rate allowance.

Central Hudson takes exception to the denial of deferral authority.

Discussion - The RD was correct in explaining that automatic deferral authority, while frequently provided in negotiated multi-year rate plans, is normally not necessary for a one-year rate case, absent unusual circumstances. Basing the rate allowance for uncollectibles on the Company’s most recent experience ensures that the amount is reasonable. The Company also has access to our normal procedures for requesting deferral authority, should that become necessary. In addition if our pending proceeding finds that further measures are required, Central Hudson will be able to avail itself of them. The exception is denied.

D. TAXES

1. Property Taxes

The RD recommended rejection of Central Hudson's request for bilateral reconciliation of property tax costs on the ground that an update of the forecast expense prior to an order would be sufficient for a one-year rate case. It also found that a mechanism providing for the sharing of property tax litigation related legal expenses between the Company and ratepayers made sense, but recommended that it not be adopted at this time.

Central Hudson takes exception, arguing that both these recommendations are inconsistent with the recent Con Edison Order which approved deferral and reconciliation of property taxes in that one-year case because of the uncertainties generated by the weak economy. That Order also expressed support for aggressive legal action to lower taxes.[20]

Staff agrees with the RD's conclusions but takes exception to the suggestion that the litigation cost sharing mechanism might be worth exploring further in future proceedings. It argues that the Con Edison Order dealt with a unique situation in which property taxes accounted for nearly

[20] Con Edison Order, p. 110.

33% of the rate increase as compared with less than 1% for Central Hudson in this case.

Discussion - In Con Edison, we were dealing with extraordinary increases in property taxes imposed by the City of New York, representing fully 29% of the utility's total revenue requirement.[21] An underestimation of the proper rate allowance for this expense category, given the current economic volatility, could have had a serious adverse impact on Con Edison's finances.

Here, property taxes account for only about 10% of the Company's revenue requirement, and there is no indication of any unusual movement toward higher assessments or rates in Central Hudson's service territory. Consequently, we find that the RD's recommendation that the Company be allowed to update the allowance for this expense based on the latest information available, combined with our standard policy on requests for deferral authority, provides Central Hudson with a reasonable rate allowance. The Company's exception on this point is denied.[22]

With regard to property tax litigation expenses, we ordinarily allow reimbursement of such costs from the proceeds of successful tax challenges prior to sharing the balance with ratepayers. This provides an appropriate incentive to pursue cases having a reasonable chance of success, without promoting litigation for litigation's sake. Therefore, we deny the Company's exception. If the Company wishes to propose a different approach in the future, it is free to do so.

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[21] Con Edison Order p. 106.

[22] In addition, as Staff correctly points out in its Brief Opposing Exceptions, the update for this expense is to be based on the most recent assessment information available and should not include a projection of future assessments.

2. Avoided Cost Interest Capitalized

The RD recommended adoption of Staff's adjustment to the rate allowance associated with this item. Central Hudson excepts saying that it determined the amount included in its filing by following the formula set forth in the Commission's 1988 policy statement addressing the requirements of the Tax Reform Act of 1986.[23] Staff argues that the policy statement merely provided an example of the normal calculation; that Central Hudson needed to take into account the nature of its actual financing activities related to its capital program; and that it did not do so correctly.

Discussion - This issue involves timing differences in the recognition of income taxes created by differing tax and rate accounting rules governing the capitalization of interest expense. The example included in the policy statement cited by the parties was intended to illustrate the treatment of avoided cost interest capitalized for typical utility financing of capital projects. It was not designed as a template to be used regardless of the tax implications of the Company's actual financing of its capital projects. The RD correctly recognized that Staff's adjustment produces the desired result of matching the benefit of the interest deduction for tax purposes with the recovery of the associated capitalized interest. The Company's exception is denied.

E. RATE BASE – CAPITAL EXPENDITURES

1. Capital Expenditure Targets

Staff proposed a number of capital expenditure target mechanisms having certain characteristics in common: (i) establishment of a fixed expenditure target based on Central

[23] Case 29465, Proceeding on Motion of the Commission as to the Proposed Accounting and Ratemaking Procedures to Implement Requirements of the Tax Reform Act of 1986 as they Affect Public Utilities (issued July 7, 1987).

Hudson’s capital budget; (ii) recovery for the benefit of ratepayers of the revenue requirement effect, including carrying charges at the pre-tax rate of return and associated depreciation expense, of any shortfalls in expenditures; and (iii) no automatic deferral of carrying charges and depreciation for over expenditures. Staff says these measures provide an incentive both for cost control and for the completion of needed capital improvements.

The RD found that (a) no evidence had been presented to indicate any problems with the management of capital expenditures by the Company in the past that would warrant these mechanisms; (b) the resulting targets materially alter the purpose of the capital expenditure budgets prepared by the Company; and (c) the mechanisms are misaligned with the interests of ratepayers in that they create both an incentive to overestimate capital costs in the future, and a disincentive to achieve cost savings in the execution of projects. The RD acknowledged the risk that the utility could postpone capital projects in the short run to enhance earnings, with possible long-term detriment to the infrastructure, but suggested that this could better be addressed through effective monitoring of capital construction rather than budgeting.

Staff excepts arguing that (a) the RD's monitoring solution provides no remedy for ratepayers if underspending actually occurs; (b) the notion that Central Hudson's incentive to reduce costs would be diminished is purely speculative, and no evidence was presented quantifying capital savings achieved through management of capital projects in relation to cost forecasts; (c) the proposals do not increase business risk because they eliminate costly prudence investigations; and (d) similar measures have been adopted for both Con Edison and Orange & Rockland Utilities.

Discussion - On this issue, we fundamentally disagree with the RD. As Staff notes, we have adopted these capital expenditure target mechanisms, with the one-way true-up feature for both Con Edison and Orange and Rockland. They provide necessary protection for ratepayers against both over and under expenditures, and are appropriate even for utilities with no prior history of missing spending forecasts.

The RD's concern that the deferral of the revenue requirement effect of under expenditures for the benefit of ratepayers may diminish the Company's incentive to control costs, or cause it to inflate its budget estimates, is unwarranted. Under Staff's proposals, if the Company overspends, it receives no immediate return on the excess outlay. If it underspends, it loses a return on part of the allowance in rate base, but it has not had to make any investment to support that portion of the allowance, and has lost nothing out-of-pocket. Therefore, the Company is considerably better off coming in under budget and has a strong incentive to do so. Furthermore, the one-way downward true-up assures that it cannot benefit at ratepayers' expense by unnecessarily inflating its budget.

Accordingly, we grant Staff's exceptions and adopt the target and deferral mechanisms it proposed for electric, gas and common plant, with the associated reporting requirements.

2. Spackenkill Substation

In response to the RD's request for an updated schedule for completion of this project, Central Hudson stated that it did not expect the Spackenkill Substation to be placed in service prior to June 2010. It agreed with the RD’s recommendation that the project be removed from rate base and accrue carrying charges at the pre-tax rate of return based on actual project costs.

Staff excepts to the Company's being allowed to update its forecast in-service date, and to the allowance of carrying charges on costs that could exceed the forecast amount included in the rate filing. Staff also, in effect, requests clarification that deferral will be permitted only if the station is put in service during the rate year, contrary to the Company's interpretation of the RD.

Discussion - Staff's first exception is moot in that the Company's update did not change its previous forecast. Its request for clarification and its exception concerning the deferral of carrying charges are granted. Deferral is authorized only on the lesser of the actual cost incurred by the Company for this station, or the $6.7 million rate base allowance, and then, only if the station is placed in service during the rate year.

3. Transmission Sag Mitigation Program - Capital Component

As noted above, there is no dispute as to the need for this program which is expected to continue into 2012. For the rate year, Central Hudson proposed to replace 213 transmission line structures at an estimated cost of $6.2 million. The total program will encompass approximately 810 replacements at a cost of about $23 million. Staff proposed a specific target and true-up mechanism for the rate year which the RD concluded was unnecessary.

Discussion - We do not find it necessary to discuss in detail the various arguments and counterarguments presented by the parties concerning the need for a target mechanism specific to this program. As we stated above, the transmission sag mitigation program is a discrete undertaking important to safety that we expect the Company to complete in accordance with the schedule it has proposed. The potential for gaming of earnings through the timing of replacements is, therefore, minimal because any under expenditure in the rate year will eventually have to be made up in later years in order for all the required replacements to be made. To enable us to track those expenditures and ensure that the costs for which ratepayers are responsible are justified, we direct that the carrying charges and depreciation expense associated with any over or under expenditures be deferred subject to true-up upon completion of the program.

4. Earnings Base/Capitalization (EB Cap) Adjustment

Central Hudson takes exception to the RD's recommendation that the Company be required to provide better information concerning the factors underlying changes in its EB Cap adjustment in future rate filings. It says the recommendation seems to require a lead/lag study, which we have previously found to be unnecessary.

Discussion - We deny the exception, but clarify that no specific study is required. The Company is simply directed to provide sufficient information to give our Staff a clear understanding of the drivers of changes in the EB Cap adjustment from case to case.

F. DEPRECIATION

1. Depreciation - Gas Plant

The RD discussed three methods of accounting for negative net salvage associated with the retirement of long-lived gas distribution mains and services. The Company advocated "standard" depreciation, which recovers the projected negative net salvage cost over the life of the asset. Staff supported fixing the negative net salvage rate permanently at 60% of original cost for depreciation purposes, with the balance of the actual net cost of removal expensed currently. The RD recommended continuation of the approach adopted in the Company's last rate case, which also provided for the negative net salvage rate to be fixed at 60% and a portion expensed, but allowed any excess removal costs over and above the amount expensed to be charged to the depreciation reserve.

The Company takes exception to the RD's recommendation, repeating its contentions that the methodologies it proposes are "standard" and avoid intergenerational inequities. It also argues that the RD erred in not adopting its proposal to increase the negative net salvage rate for gas services to 70% in light of evidence that the actual rate is already substantially higher.

Staff also takes exception, pointing out that the method recommended by the RD has never been accepted outside of a negotiated settlement, while Staff's proposed treatment of net salvage for these accounts was applied to Central Hudson for many years prior to adoption of the current rate plan. The expensing of excess costs of removal, Staff notes, helps to mitigate the impact of inflationary growth in net salvage expense on the size of the depreciation reserve deficiency which ratepayers may be required to support for decades before retirement of these long-lived assets.

Staff also responds to the suggestion that the current net salvage rate for gas services be increased from 60% to 70% by stating that it does little to address the core problem of the impact of inflation on removal costs, while increasing current depreciation rates.

Discussion - We find that the RD’s effort to recommend a middle ground between Staff and Company positions was misguided in this instance. The treatment of negative net salvage it recommends was uniquely the product of a negotiated, multi-year rate plan in which less than ideal provisions in one area may have been acceptable in light of the net value of the overall package. We continue to share Staff’s concern for constraining growth in the depreciation reserve deficiency driven by inflationary pressure on removal costs, which our pre-rate plan methodology was intended to address. Accordingly, we grant Staff’s exception, adopting its proposal for the current expensing of excess negative net salvage.

For the same reasons, we also deny the Company’s exception to the RD’s failure to recommend an increase in the negative net salvage rate from 60% to 70% of cost. This change will increase depreciation expense while doing little to stem the growth of the depreciation reserve deficiency.

2. Depreciation - Electric Plant

The RD adopted Staff's position concerning the average service lives and/or survivor curves for ten electric accounts. It found, in essence, that we are not required to accept the judgment of the Company's expert witness concerning likely changes in the historic pattern of retirements as being superior to the conclusions reached by Staff through evaluation of the historical results. It also recommended adoption of Staff's proposed reduction in the negative net salvage rates for 13 accounts based on Staff’s analysis of actual costs incurred over the most recent five years.

Central Hudson excepts as to service lives and retirement curves, saying that both the Commission and NARUC have found that it is appropriate to consider new factors influencing plant retirements in addition to merely relying on past history. On net salvage, it says the RD inappropriately provides an amount for negative net salvage that reflects only current activity and not the expected cost over the life of the assets.

Discussion - We are not persuaded that the RD erred in concluding that the judgment of the Company’s expert witness does not necessarily produce a more accurate forecast of depreciation than that recommended by Staff. We also agree that there is nothing extraordinary about Staff's use of recent historic data as a check to ensure that allowances for net salvage received by Central Hudson reflect its actual requirements. The exceptions are denied.

3. Depreciation - Common Plant

Initially, the Company proposed significant reductions to the amortization periods for six common accounts. Based on its comparison of the periods currently used by the Company with those used by other utilities, Staff recommended no change. The RD proposed a middle ground, bringing Central Hudson's amortization periods closer to the average lives used by the other utilities.

Central Hudson takes exception to that recommendation. It argues that it should be authorized to use the same amortization periods as Con Edison, which, it says, have been closely scrutinized in recent cases. Also, the Company points out that various sub-accounts within the six common accounts addressed by the RD have amortization periods that are substantially different from both those proposed by either the Company or the RD. Finally, it says that if its proposal is not approved, the existing service lives should be continued; that is, Staff's position should be adopted.

Staff responds by pointing out that the Con Edison service lives are the lowest of all the options presented, and it expresses support for the RD's recommendation.

Discussion - Central Hudson's exception suggests that its original proposal was either incomplete or misleading. The Company initially asked for a reduction in the amortization period for account 391 from 8 to 5 years, but now shows that sub-accounts within that account had service lives of 8, 12 and 20 years. A five-year amortization period for such an account is not reasonable. Given this lack of detail, we decline to approve the Company’s proposal and instead adopt Staff's original position that no change in amortization periods be made at this time.

G. DISPOSITION OF DEFERRED ITEMS

1. Electric Bill Credit

No party disagreed with Central Hudson's proposal to net certain deferred debits and credits (also known as regulatory assets and liabilities). For electric operations, this process will leave a net liability owed to ratepayers, which the Company proposed to pay out to customers over the rate year as an electric bill credit. The RD adopted the EBC concept, but recommended that the funds be paid out in equal installments over three years in order to reduce the possibility of "bill shock" from expiration of the credit, or at least to postpone it until hoped-for better economic circumstances have arrived. The RD also noted concerns about the fairness of the method proposed by the Company for allocating the EBC among rate classes, and asked the parties for further comment.

In response, no party takes exception to the EBC approach, but several suggest modifications to the mechanism as proposed in the RD. Staff recommends that some portion of the available credit be retained for future rate mitigation, and that the EBC be phased, with the largest payout in the first year and progressively smaller credits in subsequent years. Multiple Intervenors opposes Staff's call for retention of part of the available credit, but could support the phasing proposal. Central Hudson continues to call for full payout in the rate year.

With respect to allocation of the credit among classes, Staff supports apportionment in the same manner as any rate increase authorized for electric delivery service. Central Hudson suggests use of the 69% energy, 31% demand ratio that was proposed by Staff for the allocation of Power Purchase Agreement benefits related to Nine Mile Point Unit 2. MI seeks only equitable treatment for the larger customers it represents, saying that it could accept several different ratios based on a mix of factors including demand, volume and plant in service.

Discussion - We agree with the RD that the current economic circumstances constitute a "rainy day" fully justifying the utilization of these funds to moderate rates, but we also agree with Staff that completely depleting ratepayers' "savings" is not wise. Of the $43 million net credit available, we direct that $36 million be paid out as an EBC.

We also adopt Staff's proposal on phasing the credit and direct that it be paid out $20 million in the rate year, $10 million in the year ending June 30, 2011, and $6 million in the year ending June 30, 2012. This will provide the greatest benefit to ratepayers during the current economic downturn while moderating the impact of the credit's eventual expiration. The amounts specified for years two and three are subject to modification upon a showing of good cause in a subsequent rate filing or other petition to the Commission.

On the issue of allocation, since the primary purpose of the EBC is to help offset the electric delivery rate increase, we approve the distribution of the credit in proportion to class responsibility for that increase as being a fair and sensible approach. The allocated credits will be refunded to customers on a kilowatt-hour or kilowatt basis, consistent with the manner in which each class is billed.

H. COST OF CAPITAL

1. Capital Structure.

The RD found that Central Hudson's equity ratio was at the low end for companies with its A credit rating, and that growing interest rate spreads justified measures to maintain that rating. It, therefore, recommended moving the equity ratio to the higher of 47% or the Company's actual ratio as of the end of the first quarter of 2009, a compromise between the 46% conceded by Staff to be reasonable and the Company's requested 48%.

Both Staff and Central Hudson take exception to this recommendation, with the Company noting that it has, in fact, achieved an equity ratio of 48% as a result of an April 2009 capital infusion of $25 million from its parent company. Staff, while disagreeing with the 47% recommended by the RD, says that it is willing to accept the actual equity ratio of 46.68% (which it calculates using its capital structure methodology as updated to March 31, 2009).

Staff also argues, in effect, that it is not appropriate to accept the April equity infusion for purposes of calculating the Company's authorized rate of return without considering its full impact on Central Hudson's finances. It says that if Central Hudson's parent company financed this investment with debt, as Staff understands to be the case, a "double leverage" situation will have been created which would justify an adjustment to the utility's required return on equity because of the lower debt-based cost of the new equity addition.

Discussion - The April infusion of equity by CHEG will not be considered. As Staff makes clear, this is not a simple question of recognizing the achievement of a 48% ratio. The manner in which the new equity was created could require a re-evaluation of the Company's financial structure. Under the circumstances, including the fact that the Company has stated its intention to increase its equity ratio from 46% in September 2008 to 48%, we deny all exceptions and adopt the RD's recommendation. This result is consistent with the Company's gradually increasing its equity ratio without the use of an equity infusion potentially funded by debt, and provides a reasonable equity cushion given all of the aspects of our Order.

2. Return on Equity Generally

The RD concluded a 10.05% return on equity (ROE) was appropriate, based on adopting Staff's methodology along with a capital structure adjustment to the ROE proposed by the Company. In addition, the RD stressed that it was more essential than ever to update the ROE methodology using the most recent data possible shortly before we make our decision in the rate proceeding. Central Hudson asserts that the RD should not have adopted any aspect of Staff's methodology for calculating return on equity because Staff failed to affirmatively support that methodology as required by our order in Con Edison. Staff responds that it devoted over forty pages in its initial brief to the explanation and support of its methods.

Discussion – With the exception of the capital structure adjustment and the calculation of the risk-free rate in the Capital Asset Pricing Model (CAPM), we adopt the methodology used in the RD to calculate the allowed ROE. In addition, we have updated this methodology for data through May 2009. Our Con Edison Order stated that challenged practices must be supported with "substantive reasons" provided "on the record or in precedent cited in trial briefs."[24] Staff has cited in its briefs to numerous cases in which we directly addressed the same methodological challenges made in this case, and explained our reasons for rejecting them. The exception is denied.

3. Return on Equity - Adjustment for Capital Structure

Central Hudson takes exception to the RD's reduction in the size of its proposed adjustment for differences between its equity ratio and the average equity ratio of the proxy group

[24] Con Edison Order p. 120-21.

used in calculating ROE. It characterizes this as a "contingent" exception that would not be raised if its request for a 48% equity ratio were granted.

Staff takes exception to the allowance of a capital structure adjustment of any size. It points out that the total risk of an investment, whether debt or equity, is the sum of business and financial risk. A higher equity ratio (all else being equal) means a lower financial risk. Therefore, a company with high business risk and a high equity ratio (low financial risk) might very well have the same credit rating and equity return as one with low business risk and a low equity ratio (high financial risk). Central Hudson's business risk, as reflected by its beta, was substantially lower than that of the proxy group. It would be expected, then, that the proxy group's average financial risk, would be lower (and its equity ratio higher). Consequently, Staff says, there is no reason to conclude that the difference in equity ratios between the proxy group and Central Hudson reflects a difference in total risk or expected return.

MI also takes exception to the adjustment for capital structure, contending that it is subsumed within the credit quality adjustment performed by Staff.

Discussion - We agree with the arguments presented by Staff and MI. Credit ratings reflect the rating agency's judgment of the total risk that will be incurred by a party who supplies capital to the rated business. Therefore, Staff's credit quality adjustment subsumes the financial risk represented by the Company's equity ratio adjustment, and we grant Staff’s exception. This conclusion moots the Company's related exception concerning the relative weight accorded by the RD to the Company's equity ratio adjustment and Staff's credit quality adjustment.

4. Return on Equity – Credit Quality Adjustment

Central Hudson objects to the imputation of a credit quality adjustment. The RD found that Staff had made a credible argument that the proxy group used in determining the rate of return required by investors was riskier than Central Hudson and an adjustment to the Company's ROE was needed to reflect the lower risk of Central Hudson. As we recently discussed at length in the Con Edison Order, bond ratings are a way for investors to measure differences in risk.[25] Given that returns are a function of risk, it is logical that returns for companies with lower risk will be lower than for companies with higher risk. Further, it is reasonable to assume that such risk differentials would be magnified for equity holders. We therefore deny the Company's exception and adopt a 48 basis point credit quality adjustment.

5. Return on Equity - RDM Adjustment

Central Hudson takes exception to the RD's adoption of a 10 basis point reduction in authorized return on equity proposed by Staff as a means of reflecting the lower risk of a revenue shortfall resulting from the adoption of RDMs. It contends that it is unfair to adjust for lower risk without also adjusting for higher risk that would be generated by other recommendations in the RD.

Staff responds that the recommended adjustment is necessary to reflect the fact that most of the companies in its proxy group do not have RDMs. The types of risk referred to by Central Hudson, by contrast, are common to all regulated utilities. Furthermore, Staff notes, the Company's own witness recognized that adoption of an RDM justified a reduction in return on equity to reflect lower business risk.

[25] Con Edison Order, pp. 134-137.

Discussion **-** Central Hudson cites no specific recommendations that would increase risk in a manner different from decisions that are commonly a part of the rate setting process. The risks associated with that process are common to both Central Hudson and the members of the proxy group used by Staff in determining ROE. An RDM, by contrast, marks a substantial departure from traditional utility cost recovery, and these mechanisms are not yet widespread among proxy group utilities. A separate adjustment to ROE is justified to reflect this difference. Accordingly, the Company's exception is denied.

6. Return on Equity – Summary

As the RD stated, for nearly 15 years we have consistently employed an ROE methodology that gives the result of a two-state Discounted Cash Flow (DCF) model twice the weight of the results of the CAPM methodologies. Further, we have specifically rejected the Company’s proposed Risk Premium method in several past cases. We find that our ROE methodology provides stable, reasonable results while relying primarily on directly observed investor behavior.

For the CAPM methodologies, we have used the latest three-month average of 10- and 30-year Treasury bonds to determine the risk-free rate. While Staff’s methodology adopted by the RD used six months of data to determine the risk-free rate, in the recent Con Edison Order we expressed concern with using such a long period at this time and noted that a three-month average is consistent with the time period the Value Line data is derived from.[26]

We adopt the credit quality adjustment supported by Staff, as well as its RDM adjustment. We reject the Company’s capital structure adjustment for the reasons discussed above.

[26] Con Edison Order, pp. 128.

We also reject any issuance expense adjustment, as we have repeatedly stated that such costs are only to be recovered if equity is expected to be issued during the rate year.

The result of our ROE methodology, as updated with data through May 2009, is 10.0%.

7. Cost of Debt

The RD points out that there is agreement between the Company and Staff as to how to update the cost of debt estimate, as well as what debt costs should be reconciled. Both the Company and Staff request clarification that the Company will be permitted true-up and deferral of debt cost for both auction rate debt and new long-term debt issuances, rather than just auction rate debt as implied by the RD. That clarification is uncontested and is granted.

As to the cost of debt to be employed, the Company stated in its Brief Opposing Exceptions that the estimated debt cost for future issuances should be increased to reflect adjustments due to a new issue premium and a liquidity premium. Staff, in its Brief Opposing Exceptions, also acknowledged such concerns and suggested that 100 basis points be added to future debt cost estimates to account for these adjustments. Because the costs will be reconciled, the actual debt costs the Company incurs will be recovered. The debt cost we estimate is used only to set rates.

We are estimating the cost of debt to be 4.86%, using the assumption that the October 2009 debt issuance planned will be issued at a rate of 7.15% (the recent average cost of debt rated A2 by Moody’s Investors Service plus 100 basis points).

8. Overall Rate of Return

Given the decisions we have made regarding the Company’s capital structure, ROE, and debt cost rate, Central Hudson’s overall after-tax rate of return will be as follows:

Component	Percentage	Cost Rate	Weighted Cost
Long-Term Debt	49.77%	4.86%	2.42%
Customer Deposits	0.91%	4.85%	0.04%
Preferred Stock	2.32%	5.05%	0.12%
Common Equity	47.00%	10.00%	4.70%
Total	100.00%		7.28%

I. COST OF SERVICE, REVENUE ALLOCATION, RATE DESIGN AND RELATED MATTERS

1. Cost of Service

a. Allocation of Common Costs

Both Central Hudson and Staff take exception to the RD's conclusion that 80% of the cost of functions common to both the electric and gas businesses be recovered in electric rates and 20% in gas rates – a significant change from the current 85% - 15% split. The Company argues that the RD relied too heavily on quantitative measures and did not give sufficient weight to management judgment. It notes that the recommended change will shift approximately $2.9 million to gas rates; a shift that Staff says will increase gas rates by 6%. Staff and the Company both suggest that any change in the allocation ratio be phased in over several years. Staff adds that the quantitative factors used by the Company to estimate the appropriate ratio produce an 81.3%/18.7% split between electric and gas, and recommends that no more than a 1% movement toward that ratio be ordered in this case.

Discussion - We consistently endeavor to ensure that the rates paid by utility customers correctly reflect the costs incurred to serve them. If the quantitative measures cited by Staff are valid indicators of the appropriate ratio for allocation of common costs, it is clear that Central Hudson's rates currently incorporate a subsidy benefiting gas customers at the expense of electric.

We note, however, that a change in this allocation ratio is an extraordinary event. The record indicates that it has happened only once for Central Hudson in the last 15-plus years, and that revision was triggered by the very significant change in the make-up of the utility's business resulting from its divestiture of most of its generating plants.

The quantitative factors used by the Company are proxies for, not direct measures of, the actual common costs incurred for the electric and gas businesses. Some judgment, as the Company argues, is needed in making a proper cost allocation. We do not feel that we are in a position to exercise that judgment on this record.

Accordingly, we direct that the existing allocation ratio be retained for the purpose of setting rates in this case, but we also find that the evidence clearly points to the need for a more thorough assessment of this issue in the future. Therefore, we direct that Central Hudson, in its next rate filing, provide an objective analysis of the relative responsibility of the gas and electric businesses for the costs of common functions. To the extent the Company believes that analysis should be tempered by management judgment, the basis for that judgment should be fully and clearly explained.

b. Classification of Gas Distribution Mains

Staff proposed to reclassify gas distribution main costs for purposes of the pro forma embedded cost of service study by assigning them entirely to the demand component of rates. Currently, based on the zero-intercept methodology that Central Hudson has used since at least 1990, those costs are classified 55% to the customer component of rates and only 45% to the demand component. Because gas mains constitute 20% of the total cost of gas service, the reclassification results in a very large shift in cost responsibility from residential customers to large gas users. The RD noted that both the existing and proposed methodologies are deemed acceptable by NARUC with no indication that one or the other is superior. It concluded that such a large shift in cost responsibility should not be adopted without compelling evidence that it is necessary to rectify some serious inequity.

Staff takes exception to the recommendation against reclassification, suggesting that the RD did not give adequate weight to Staff's arguments demonstrating that mains costs are driven to a much greater extent by gas demand than by number of customers. MI and the Company support the RD's recommendation.

<u>Discussion</u> - Initially, we disagree with the implicit suggestion by the RD that the standard for changing a methodology that affects the allocation of cost responsibility among customers somehow becomes more difficult as the existing approach gains seniority. We have stated repeatedly that we strive to match cost responsibility with cost causation. Any showing that this objective is not being met is sufficient to warrant consideration of a change, even if it means abandoning long-held assumptions.

At the same time, as we discuss in connection with customer charges and the common cost allocation ratio, we have consistently taken a gradual approach when a sudden, full correction would create unacceptable bill impacts. That situation clearly exists here.

Finally, although we find the arguments persuasive as to the assignment of a greater proportion of gas mains costs to the demand component, we are not convinced on this record that <u>no</u> mains costs should be classified as customer related. Accordingly, we direct that for the purpose of setting rates in this case, the allocation of gas mains costs should be 65% demand and 35% customer. This is consistent with the ratio that we adopted for National Grid in approving a Joint Proposal in its recent gas rate case.[27]

c. Electric Pro Forma ECOS Study

MI excepts to the RD's failure to require modifications to this study. It continues to object to the inclusion of commodity procurement costs and electric production costs in what is supposed to be a delivery cost study. It notes that the Company's witness agreed that neither production nor commodity procurement costs are required for delivery service. Furthermore, MI says, even if the inclusion of commodity procurement costs can be justified, they should not have been allocated volumetrically since the Company's ECOS witness acknowledged that they do not vary with volume.

Staff states in response that both the production and commodity procurement costs must be considered in developing the electric revenue requirement. It notes that the same methodology was used for the ECOS study in the Company's last rate case.

Discussion **-** MI's exception is granted as to the allocation of procurement costs, and Central Hudson is directed to redo its pro forma study using an allocator appropriate for labor costs that do not vary with volume. Allocation of procurement costs to SC13 customers, and then unbundling them to the Merchant Function Charge, is appropriate in light of the Company's continuing POLR function. Doing so volumetrically, however, improperly shifts apparent cost responsibility toward large customers, generating an unreasonably low pro forma rate of return for the SC13 class.

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[27] Case08-G-0609, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Gas Service, Order Adopting the Terms of a Joint Proposal and Implementing a State Assessment Surcharge (issued May 15, 2009), p. 6.

As stated in the RD, the inclusion of certain generation costs in delivery rates was previously approved by us and MI's exceptions concerning these costs are denied.

d. Electric Delivery-Only ECOS

Staff takes exception to the RD's failure to recommend that Central Hudson be required to submit a delivery-only historic embedded cost of service study with its next rate filing. It notes that the Company has indicated its willingness to do so, with certain caveats. Central Hudson says that it will have to make certain simplifying assumptions in order to segregate commodity-related costs, and it does not want to be bound to vouch for the accuracy of the results.

Discussion - Staff believes that a delivery-only historic embedded cost of service study will facilitate comparison with the pro forma study, making it possible to identify where changes are occurring. We agree that the capability to better understand variations in costs across time periods, is valuable and we grant Staff's exception. The Company will be required to submit the requested study with its next rate filing, but it will be free to state its disagreement with any results it considers to be incorrect or misleading.

e. Gas Marginal Cost of Service Study

Staff recommended that the Company be required to include a marginal cost of service study with its next gas rate filing, and repeated this request in its Brief on Exceptions. The issue was not contested or briefed and was not addressed in the RD. In its Brief Opposing Exceptions, Central Hudson questions whether there is a functional need for such a study, and adds that if one is required, it will need adequate time to collect the required data, perform the analysis, and prepare the documentation.

Discussion - As Staff noted, a marginal cost study remains necessary to ensure that tail block rates are set appropriately. Central Hudson’s next gas rate filing should include such a study. If the Company believes it has not had adequate time to complete a study by the time of the filing, it should explain why that is the case and propose a schedule for completion.

f. Gas Service Classification No. 11 (SC11).

(1) Crow's Nest Brook and Orr's Mill Road Regulator Stations

The RD requested comments on DOD/FEA's assertion that all system customers should share the cost of these regulator stations. Currently, 89% of the cost of Crow's Nest Brook and 100% of the cost of Orr's Mill Road are allocated to Service Class 11 DLM, the U.S. Military Academy at West Point.

Staff responds that it is unsure how the stations benefit all customers and, therefore, cannot address the allocation of costs. Central Hudson says that the Orr's Mill Road station is used only for service to West Point, while the costs of the Crow's Nest Brook station are allocated between West Point and the service classes of downstream customers in proportion to their usage.

Discussion - No good basis has been presented for upsetting the Company's allocation of costs for these facilities. Responsibility is currently borne by the customers that use them in proportion to their usage.

(2) Cost of Meters

Usage by West Point is measured by taking the difference between upstream and downstream meters on each of the lines serving the facility. The Company allocates the full cost of the meters to West Point. The RD found that some portion of the cost of downstream meters should be allocated to downstream customers, and asked for comment on an appropriate ratio.

Central Hudson excepts, saying that the individual meters of downstream customers cannot all be read simultaneously, which would be necessary to "back out" West Point usage if the downstream meters were not in place. Staff stated that it did not except to the RD's recommendation, but had no comment on how to allocate the costs. DOD/FEA initially deferred to the other parties for a determination, but in its Brief Opposing Exceptions it asserted that the meters should be charged to the customer classes represented by the downstream customers.

Discussion - The downstream meters would not be needed if there were no downstream customers, and they would not be needed if there were no West Point. Since both customer groups do exist, the cost of these meters should be allocated between them on the same basis as the regulator stations discussed above; that is, in proportion to the customers' usage of the lines on which the meters are located.

(3) Certification Requirement for SC11 DLM

Central Hudson excepts to the RD's requirement that the Company certify in its next rate filing that its allocation of costs to the SC11 DLM class does not include the cost of mains smaller than 6 inches. The Company says it was not required to adhere to this mains allocation limitation beyond the term of its last negotiated rate plan, and that it agreed to the allocation in this case because of the facts, not because of an obligation.

DOD/FEA’s response recognizes that Central Hudson can propose changes in its allocation of costs to the SC11 DLM class, but notes that the allocation of the costs of smaller mains included in Central Hudson's initial filing in this case would have been costly to West Point and could easily have been overlooked. It asks that proposed changes in future rate cases be clearly identified.

Discussion - DOD/FEA's request is reasonable. Central Hudson's exception is granted as to the requirement for adherence to the cost allocation formula currently in place, but the Company is directed to ensure that any change in the allocation of mains to the SC11 DLM class proposed in a future rate filing is clearly flagged.

2. Revenue Allocation

a. Electric Revenue Allocation

Staff excepts to the RD's conclusion that Staff's proposed 2.18 times system average constraint on rate increases for the SC2-Non-Demand, SC5 Area Lighting, SC13 Substation and SC13 Transmission classes is unreasonable. It notes that very large interclass subsidies currently exist in favor of these classes; says that it is appropriate to consider commodity prices in evaluating the impact of higher delivery rates; argues that accrued power purchase benefits inuring to these customers should be considered; and contends that large dollar increases in customer bills can be ignored if they represent small percentage increases. Finally, Staff says that if the RD's statement "that everyone should share the pain equally and that disproportionate rate shocks should be avoided" means that ECOS studies should be ignored, it objects.

MI argues that now is not the time to impose major increases on SC13 customers. It recommends that the constraint be set in the range of 1.20 to 1.25 as was recommended by the RD for gas.

In its Brief Opposing Exceptions, Staff says that given the likely size of the rate increase, it would now agree to lower and upper constraints of 75% and 125%.

Discussion - The RD recommended that a final determination of appropriate constraints should await a re-run of the ECOS study which the Company was to provide with its Brief on Exceptions. That study shows that the ratio of the SC13 rate of return to the system average return has improved from -1.19 to -0.58. This, combined with the size of the increase we are authorizing, suggests that a lower allocation constraint is appropriate. We direct that a constraint of 1.25 times the system average increase be used. This is within the range supported by MI and is acceptable to DPS Staff.

b. Gas Revenue Allocation

The RD recommended a sliding scale for the upper constraint on allocation of a gas rate increase among service classes, varying from 120% to 150% in inverse proportion to the size of the overall rate increase. MI argues that current difficult economic conditions dictate that a 120% constraint be applied. No other party comments.

Discussion - Because of the size of the rate increase we are authorizing, the RD's proposed formula is moot and the 120% constraint will be adopted.

3. Rate Design

a. Customer Charges

No party disputes the finding that Central Hudson's embedded cost of service studies indicate the customer charge components of the Company's gas and electric rates do not reflect the full amount of the customer-related costs incurred by the utility in providing delivery service. There is, however, a difference of opinion as to how far toward the cost-based rates suggested by those studies the current charges should be moved.

The RD recommended adoption of the increases proposed by the Company. For most residential customers, this would raise the customer charge for electric service by $9.00 per month, and for gas service by $7.00.

Staff takes exception to this recommendation, arguing that the customer charge for residential customers should be increased by only $2.00 for electric service and $3.00 for gas.

It points out that while we have recognized the desirability of moving these charges toward the levels indicated by the embedded cost of service studies, we have consistently followed a policy of moving gradually in that direction in order to avoid adverse bill impacts for low-usage customers. This policy, it says, is well illustrated by the fact that we have raised the customer charge for residential electric customers by more than $2.00 only once since 1996.

Discussion - Staff’s explanation of our policy with regard to the gradual alignment of customer charges with customer costs for the residential service classes is accurate, and we are not persuaded that any good reason for deviating from it has been shown. Therefore, we adopt Staff’s position as to the increases for these classes.

The customer charge increases proposed by Central Hudson for commercial and industrial customers do not present similar bill impact concerns. We note, in fact, that MI supports the Company’s position as to the classes under which most large gas and electric customers take service. Accordingly, we adopt Central Hudson’s proposed charges for the non-residential classes.

b. Maximum Daily Quantity (MDQ) for SC11

Gas customers receiving firm transportation service under Central Hudson's SC11 are billed based on their MDQs which are set forth in their service agreements. If a customer's usage during the winter exceeds its MDQ on five or more days, the MDQ is automatically reset on April 1 to the average of the five highest usage days experienced.

The RD recommended adoption of a proposal proffered by the witness for DOD/FEA and supported by Multiple Intervenors that would require MDQs for SC11 customers to be automatically adjusted downward as well as upward based on peak winter usage. It made that recommendation despite finding that the proposal might be risky for customers, because the affected customers supported the change and neither Staff nor the Company objected.

The RD also suggested that the proposal might not be necessary because customers should be able to request changes to their MDQs as part of the annual renewal process for their service agreements. It noted further that the MDQ is an absolute limit, regardless of weather, so that excess usage clearly indicates the need for an increase. The same cannot be said about reduced usage which may simply result from warmer weather. The RD asked the parties to comment further on these points in their briefs on exceptions.

The Company responds that its failure to address the proposal was an oversight. It argues that the tariff change could allow SC11 customers to avoid cost responsibility to the detriment of others on the system. Staff agrees with the RD's suggestion that existing tariff provisions are adequate to allow for MDQ adjustment as necessary. MI, in contrast, says it knows of no tariff provision allowing for adjustment of the MDQ, and continues to support the change.

Discussion - We will not require the requested change to Central Hudson's SC11 tariff. As the RD noted, repeated excess usage is proof that the MDQ is too low, but the converse is not true. Reduced peak usage in any given year may say little about peak requirements generally. Customers should bear the cost of the capacity required to deliver their expected maximum usage even if that peak is not reached in some years.

Customers should, however, have the ability to conform their MDQs to their actual requirements. We clarify, therefore, that customers have the right, by notice given as required by the tariff, to request a change in MDQ at the annual renewal of their service agreements. Requested reductions supported by objectively verifiable information should not be unreasonably denied by the Company.

4. Retail Access Lost Revenue Mechanisms

a. Gas

Lost revenues associated with Central Hudson’s gas retail access program are currently recovered from ratepayers in two pieces. Fifty percent is collected through the Supply Charge component of the Merchant Function Charge (MFC), which is avoided by retail access customers, and 50% through the transition adjustment paid by all customers. The RD recommended that this mechanism be continued.

Staff takes exception. It supports 100% recovery through the transition charge, arguing that our policy statement on unbundling concluded that some supply-related costs were related to the utility's provider of last resort (POLR) function and should be recovered from all customers;[28] that the basis for adoption of a 50/50 split in the Company's last rate settlement is unstated; and that we have said that the parties are free to propose different splits in individual rate cases.

Discussion - We agree with the RD's conclusion that the current 50/50 split between the MFC and the transition charge for recovery of retail access lost revenues is a reasonable compromise, giving some benefit to retail access customers without absolving them completely of responsibility for funding POLR-related costs. Staff is correct in noting that we left open the possibility that this sharing ratio could be changed in future rate cases, but that change should not be merely another assumption. It should be supported by a new consensus of the interested parties, or by substantive analysis

[28] Case 00-M-0504, Proceeding on Motion of the Commission Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets, and Fostering the Development of Retail Competitive Opportunities, Statement of Policy on Unbundling and Order Directing Tariff Filings (issued August 25, 2004), p. 36.

which the RD found to be lacking in this case. The exception is denied.

b. Electric

Pursuant to the procedures defined in Central Hudson's last rate order, fifty percent of forecast retail access lost revenue is recovered by adding a separate component to the MFC Supply Charge on an MFC group-specific basis. The remaining fifty percent is recovered through the MFC group-specific Transition Adjustment. At the end of each rate period, a reconciliation is performed between the actual retail access-related lost revenue and the amount of retail access-related lost revenue recovered from ratepayers.

The RD recommended that the current mechanism be continued. Staff takes exception. It continues to support including 100% of forecast lost revenue in delivery rates, in part because of concerns regarding potential conflicts that might result from the tandem operation of the current mechanism and the RDM which we are adopting in this order.

SCMC and MI oppose Staff's exception. MI notes that the need to design a collection mechanism that works with an RDM does not mean that the methodology for allocating cost responsibility among customer groups has to be changed. It says that Staff's proposal simply amounts to a reversal of years of effort to achieve the unbundling of commodity and delivery rates.

Discussion - For the reasons stated in the RD, we will not modify the current allocation of cost responsibility for forecast retail access lost revenues, or require that recovery be included in base rates. Staff's exception to the RD's recommendations on these points is denied. At the same time, however, we agree with Staff that modifications to the lost revenue recovery mechanism will be required to avoid certain unintended interactions with the RDM we are adopting in this case.

Currently, Central Hudson’s MFCs, MFC-related lost revenue recovery, and Transition Adjustment charges are calculated and accomplished within each of four MFC groupings. The RDM, by contrast, must be class specific and will reconcile each class’s actual total delivery revenue (inclusive of MFC revenues) to our approved delivery revenue forecast. The concerns expressed by Staff concerning the interaction of these two mechanisms include over or under recovery of retail access lost revenues and the potential for interclass revenue transfers resulting from interaction between the class-specific RDM and the group-specific MFC.

To address these concerns we will require that MFCs and Transition Adjustment Charges be calculated and applied on a class and sub-class specific basis, thus eliminating the transference of cost responsibility between classes and sub-classes within each MFC group. Further, we will require that the final reconciliation performed as part of the retail access lost revenue recovery mechanism be discontinued for classes subject to an RDM (the RDM will provide the final reconciliation) and that it be on a class and sub-class specific basis for classes and sub-classes not subject to the RDM. Finally, MFC and Transition Adjustment Charges are to be included in the RDM targets. These three steps will ensure that the two mechanisms do not conflict and thus potentially result in over or under recovery of MFC revenues.

5. Factors of Adjustment

a. Electric

The RD recommended that voltage-specific factors of adjustment be implemented by Central Hudson. No party takes exception to this recommendation, but Staff reports that it has conferred with the Company and determined that the factors cannot be in place until August 1, 2009. MI, the principal proponent of this change, does not object to the one-month delay. We accept the proposed August 1, 2009, implementation date.

b. Gas

Central Hudson says that the RD correctly stated the standard for establishing LAUF targets, but failed to address the application of those targets in making the annual reconciliation. Inasmuch as Staff has agreed that the same methodology used in setting targets should be used for the annual reconciliations, and no other party objects, we grant the requested clarification.

6. Allocation of Power Purchase Agreement (PPA) Benefits.

Currently, the net benefits realized by Central Hudson from its below-market power purchase contract with the owners of the Nine Mile Point Unit No. 2 (NMP2) nuclear plant are flowed through the Company's Purchased Power Adjustment factor in its Electric Cost Adjustment Mechanism and allocated among the service classes and subclasses on the basis of kWh sales. Staff proposed instead that only 69% of the benefits be allocated based on energy, with the remaining 31% based on peak demand. This, it said, would better reflect the manner in which the capital costs associated with NMP2 were recovered from customers between 1988 and 2001.

The RD recommended that Staff's position be adopted, and MI takes exception. MI repeats arguments previously made in its trial briefs that the present allocation reflects one of a number of interrelated compromises incorporated in a broader settlement that should not be undone, and that reducing benefits flowing to large business customers in these difficult economic times is not a good idea.

Discussion - The PPA benefits in question resulted from Central Hudson's sale of its interest in NMP2, and it is appropriate that they be allocated in proportion to the contribution of each customer class to the utility's cost of acquiring of that interest. We concur with the RD's conclusion that Staff's proposal creates a better match between that past capital cost responsibility and the receipt of the benefits now flowing from that facility. While we appreciate that the current economic circumstances are difficult for large customers, that difficulty extends to all customer classes. MI's exception is denied.

J. SAFETY AND RELIABILITY PERFORMANCE MECHANISMS

1. Electric Reliability Performance Mechanism (ERPM)

There were no exceptions to the RD's principal recommendation that the Company's ERPM should continue with the same targets and associated negative revenue adjustments for the System Average Interruption Duration Index and the Customer Average Interruption Duration Index. There was also agreement on two project-specific targets, namely energizing the proposed Galesville substation, and completion of 150 miles of enhanced distribution main line tree clearance. There were, however, several exceptions and requests for clarification concerning the details of the mechanism.

a. Project Targets

The RD approved the use of two project targets "with a 5 basis point revenue adjustment dependent on the completion of each during the rate year."[29] Staff asks that we clarify that there will be a separate five basis point adjustment associated with each project. We grant the clarification.

[29] RD, p. 101.

b. Annual Compliance Reports

The RD endorsed a requirement for annual reports due on March 31. Staff takes exception, pointing out that it recommended separate reports due on March 31 for the index targets and on August 1 for project targets. Central Hudson objects to the additional reporting requirement.

Discussion - Staff's representation indicates that the two reports are distinct and non-duplicative. On that basis, splitting the reporting in two should not add unnecessary cost. Staff’s exception is granted.

c. Continuation

Staff takes exception to the RD's conclusion that Staff should not be permitted to unilaterally adopt new project targets each year during a continuation of the ERPM between rate cases. As a compromise it suggests that the Enhanced Tree Trimming Program, which is ongoing, continue to be a target, and that the second target be selected by consensus between Staff and the Company. If no consensus is reached, the full 10 basis point adjustment applicable to the project portion of the ERPM would be assigned to the tree-trimming program.

In response, Central Hudson says it is willing to collaborate on new project targets, and suggests that this take place during the quarterly meetings it has customarily had with Staff.

Discussion - Staff's proposal is a reasonable compromise and is adopted as a means of establishing new project targets after the rate year. The Company's suggestion that the collaboration take place during regular quarterly meetings is also a good one. No party took exception to the RD’s finding that those meetings have been valuable and that they should not be eliminated if Staff resources are sufficient to accommodate them.

d. Future Rate Cases

The RD found that requiring the Company to propose an ERPM every time it files a rate case is unnecessary because the continuation clause ensures that silence is the equivalent of consent to the existing mechanism. Staff responds that utilities sometimes propose ERPM modifications later in the rate case process, putting the other parties at a disadvantage. It asks that the Company be required in its original filing to either accept continuation of the ERPM or propose a new one.

Central Hudson says the requirement is unnecessary because silence in the original filing is sufficient.

Discussion - Staff's request is not burdensome and is consistent with our concern that original filings be complete and informative. Staff's exception is granted.

2. Service Quality Performance Mechanism (SQPM) - PSC Complaint Rate

Staff takes exception to the RD's recommendation that both the threshold complaint rate and the associated negative revenue adjustment (NRA) be kept at their current levels. It says that the existing threshold was, of necessity, only an estimate when it was set two years ago at the inception of Central Hudson's SQPM. Now that there is some history on which to base the target, leaving it far above the level of actual performance would make it ineffective. Staff also says that the NRA for Central Hudson is lower than that for all but one other utility as a percentage of common equity and should be raised to have the requisite deterrent effect.

Discussion - We understand the RD's concern that setting stricter targets in response to good performance could be perceived as punishing success, but that is not the situation here. This case is our first opportunity to establish a target for Central Hudson that reflects actual experience in the service territory. Moreover, the target of 1.7 complaints per

100,000 customers recommended by Staff is more than double the Company's recent experience and could hardly be considered burdensome. The fact that the target for a neighboring utility is higher is simply not relevant. We have always established targets on a utility-specific basis in recognition of differences among service territories that are unrelated to the quality of service provided.

Finally, we agree that the impact of potential negative revenue adjustments on earnings should be of a similar magnitude for all utilities. Accordingly, we grant Staff's exceptions.

3. Gas Safety Performance Mechanism (GSPM) - Negative Revenue Adjustments

The RD found that the size of the increase in NRAs associated with GSPM targets had not been adequately supported by Staff, and recommended that the increase be held to the rate of inflation. Staff takes exception, pointing to testimony in which it stated that the total NRA of 30 basis points it proposes is the minimum level of total regulatory liability adopted by the Commission in gas rates cases since 2005, a period that covers decisions for at least five utilities.

Discussion - Staff is correct and its exception is granted. It is our intention that the impact on earnings of failures to meet safety targets be equivalent across utilities. Staff's recommended NRAs in this case accomplish that objective.

4. GSPM - Gas Leak Repair Targets

The RD found that combining a leak backlog target with funding for a discrete number of leak repairs at a time when the number of leaks discovered is increasing is both unfair to the Company and bad policy, particularly since the Commission has previously declined to allow deferral accounting for excess repairs. Therefore, it recommended a "leaks repaired" target with deferral accounting authorized for the cost of repairs made beyond the target number.

Staff excepts saying that with a leaks repaired target, the backlog can increase, perhaps significantly. Safety concerns require that a backlog target be established to ensure that the Company will reduce the number of unrepaired leaks to a specified minimum level. Staff also opposes advance authorization for deferral of any excess gas leak repair expense the Company might experience during the rate year.

Discussion - Our previous disallowance of a request by Central Hudson for authorization to defer excess costs incurred for gas leak repairs came in the context of the Company's current rate plan. That plan was the product of negotiations. Inherent in such negotiations is a give and take through which a party may be persuaded to accept a sub-optimal result on one issue in order to secure a better than hoped for outcome on another. Central Hudson agreed to a budget for gas leak repairs that would remain fixed for the duration of its rate plan, and we assume it did so with full awareness of the risk involved.

The same reasoning does not apply going forward from this case. We are providing Central Hudson with a rate allowance that it says will be sufficient to permit it to repair 627 leaks. If it is required to repair substantially more leaks than that in order to meet a backlog target, it will necessarily have done more work than was contemplated by this rate order. If it also incurs more cost, and it can present a petition that meets the three prongs of our test, Central Hudson is free to seek deferral authorization for the excess amount expended. This resolves the potential "Catch 22" described in the RD where the Company would have to choose between overspending its budget without hope of reimbursement, or incur an NRA for not meeting the backlog goal.

Accordingly, we grant Staff's exception and adopt its proposed targets of 350 leaks for the total backlog, and 30 leaks for the repairable leak backlog.

5. GSPM - Additional Issues

Staff’s testimony included unopposed recommendations that all safety-related programs be continued until changed by the Commission, and that Central Hudson be required to report to the Director of our Office of Gas, Electricity and Water annually concerning its performance on all GSPM targets. Neither proposal was addressed directly in the RD. We agree that both should be approved as presented.

K. REVENUE DECOUPLING MECHANISMS

1. Reconciliation and Carrying Charges

Under the RDM proposals presented in this case by both Staff and the Company, variances between forecast and actual revenues will be calculated monthly, accumulated amounts will be reconciled annually, and the balances will be either surcharged or refunded to customers, with carrying charges. The RD recommended that for both mechanisms, reconciliations should be monthly, and carrying charges should be calculated at the Company's pre-tax rate of return.

Staff takes exception to both recommendations. As to the gas RDM, it suggests that frequent reconciliation is unnecessary because the weather normalization clause will account for most of the short-term variance in revenues. For the electric RDM, it suggests the use of a "circuit breaker" that would trigger reconciliation if the accumulated RDM adjustments exceeded $4 million.

For both mechanisms, Staff argues that carrying charges should accrue at the other customer capital rate. It says this lower rate is justified because there is little or no risk associated with the recovery of any amount, which is guaranteed, and because the rate is applied symmetrically both to amounts owed by, and owed to, the Company.

Central Hudson responds with respect to the reconciliation periods that Staff has failed to demonstrate any error in the RD. It also argues that the purpose of the carrying charge is to maintain the economic value of any accumulated balance. The appropriate rate, it contends, is one that reflects the time value of money to the party to whom it is owed. For the Company, that is the pre-tax rate of return.

Discussion - We grant Staff's exceptions. Monthly reconciliation will needlessly complicate the operation of the RDMs without providing any greater degree of financial protection to the Company or to customers. Instead, we accept Staff’s proposal of a $4 million reconciliation circuit breaker for the electric RDM, and we also adopt a $2 million circuit breaker for the gas RDM. The application of a weather normalization clause and the availability of the circuit breaker should prevent excessive amounts from accumulating either for credit or surcharge. This renders immaterial any risk to the economic value of sums owed to the Company through operation of the RDMs, and makes the other customer capital rate appropriate for carrying charges on accumulated balances. In addition, the use of the other customer capital rate is consistent with our past treatment of carrying charges where the amount is unknown and will be recovered over a relatively short period.

2. Electric RDM - Model

Staff excepts to the RD’s recommendation that a Unit per Customer (UPC) model be used for the electric RDM rather than a Revenue-per-Class (RPM) model. It contends that the UPC model would inappropriately allow the Company to retain the incremental net margin generated by the addition of new customers. Relying on regulatory lag to resolve this revenue disparity as suggested by the RD is inadequate, Staff says, because an RDM protects the Company against the kind of loss of revenue that might trigger the rate filing that is necessary before ratepayers can realize any benefit from customer growth. Staff differentiates the gas and electric businesses, finding the UPC model acceptable for gas utilities which continue to need an incentive to add load, while electric utilities, with nearly 100% customer penetration, do not. Finally, Staff argues that consistency of RDM design among utilities is not an arbitrary choice but rather an avoidance of duplicative effort.

Central Hudson responds that Staff's position would effectively put a "hard cap" on electric revenues, creating exactly the type of disincentive to support energy efficiency that the RDM is intended to eliminate. It says Staff relies excessively on previously decided cases and that the RD was correct in calling for greater experimentation.

Discussion - Staff is fully justified in relying on our previous conclusions concerning the appropriate form of an RDM for electric utilities. We expended a great deal of effort in previous cases addressing precisely the types of issues presented here. Until we are presented with persuasive evidence that a change should be made, we will continue to require the adoption of a Revenue per Class model for revenue decoupling mechanisms applicable to electric utilities. Staff's exception is granted.

3. Electric RDM - Exemptions

The RD recommended that SC3 be exempted from the electric RDM because there are no energy efficiency programs proposed for this class. Staff takes exception saying that even though there are no specific programs identified, Central Hudson's sales forecast attributes sales declines to the Energy Efficiency Portfolio Standard (EEPS).

MI opposes Staff's exception citing the Company's own statements that it has no energy efficiency programs planned for SC3 customers. Central Hudson did not oppose the RD's recommendation to exempt the class.

Discussion - The purpose of an RDM is to remove utility disincentives to promote energy efficiency programs, not to shift all risk of declining revenue to ratepayers. Central Hudson has no EEPS programs to promote for SC3 customers, so there is no reason to include the class in the RDM. Staff’s exception is denied.

L. HOURLY PRICING PROGRAM

1. Expansion of Hourly Pricing Program (HPP)

The RD recommended approval of Staff's proposal to lower the threshold for Central Hudson’s current HPP to encompass customers with 500 kW or more of demand. The Company takes exception. It says Staff was required to prove that the program was justified for Central Hudson's specific territory and customers, not just consistent with Commission policy generally. It adds that the RD was inconsistent in imposing these burdensome requirements on customers in bad economic times, and that the timeline proposed by Staff for implementation was excessively compressed.

Staff responds that it justified its proposal based on the benefits found by the Commission to be inherent in an HPP, that there was no showing that customers lack the capability to adapt to the program, and that the implementation schedule it proposed allowed significantly more time than was required by National Grid for a much larger effort.

Discussion - The exception is denied. As the RD noted, we have approved expansion of the mandatory hourly pricing program to include customers of this size for other utilities. Absent a showing of unique circumstances on the Central Hudson system that would render our generic conclusions inapplicable, Staff was not required to prove that benefits we have previously found to exist on a statewide basis will also be realized for Central Hudson.

The schedule and outreach efforts proposed for implementation of the program expansion appear reasonable in light of similar expansions on other utilities. Furthermore, we are adopting the RD’s recommendation, to which no party took exception, that affected customers be served with, and given an opportunity to comment on, Central Hudson's implementation plan when it is submitted to us. This will provide an additional opportunity to refine the implementation effort, if necessary, to meet any specific concerns that may be brought to our attention by those customers.

2. Hourly Pricing Program - Generation Capacity Cost.

The RD concluded that both the current volumetric allocation of UCAP costs and Staff's proposed allocation based on contribution to system peak demand were inappropriate. It recommended that the current method be retained, but that Staff and the Company explore alternative demand-based options for the next rate filing.

Staff took exception to this recommendation saying that its proposal correctly matches cost causation and responsibility. It disagrees with the RD's finding that average demand might be a better allocation factor than peak because the only successful strategy for customers under Staff's proposal would be to reduce average demand. It also notes that we have found significant benefits to be derived from reducing system peak demand and that measures which force customers to try to do so should be encouraged.

Discussion - A key to the provision of just and reasonable rates is reliability, and a key prerequisite for the provision of reliable service is the presence of an adequate amount of generation capacity. New York has had an installed generation capacity requirement for many years, long pre-dating electric restructuring. While the Company and the RD are correct that adequate generation capacity is needed 12 months a year, it is clear that the threat of shortage is highest and the need for generation capacity greatest during the peak and near-peak hours of the summer months.

Accordingly, we direct that Central Hudson adopt the Staff proposal for basing the generation capacity charge on each customer's demand during the NYISO peak hour. In contrast to Central Hudson's current generation capacity charge, the Staff proposal will send a strong price signal that will focus customers' attention on the high load hours that correspond to severe summer heat waves, which are the hours during which demand reductions benefit the State's electric system the most.

Central Hudson's current approach spreads the price signal to all 8760 hours of the year. Clearly, as for nighttime and weekend hours, this approach is inadequate, and needs to be improved. We disagree with the Company's assertion that basing the charge on the peak hour is unfairly generous to customers whose individual peaks occur in winter months. The payments made by the Company for generation capacity are tied, by the NYISO's FERC-approved tariff, to the NYISO system's peak hour; since the system peak hour only occurs in a summer month, customers' use in non-summer months costs the Company nothing in terms of its payments to the NYISO for generation capacity. Proper application of the principle of cost causation, therefore, yields a rate design which, like the Staff proposal, charges customers nothing for generation capacity cost associated with non-summer usage.

The RD noted that if all customers are somehow successful in forecasting when the critical peak hour will occur, they will reduce their consumption, and the anticipated peak will not occur, shifting the peak to some other day and hour. This contributed to the RD's rejection of the Staff approach. We do not share that concern. What it does show is that, under the Staff's approach, customers will need to acknowledge that they face a potentially high price in any summer hour in which there is a significant probability that a system peak will occur. This acknowledgment effectively spreads the generation capacity price signal received by customers beyond a single hour. In practice, this effect gives customers a signal to cut back during the afternoon hours of all summer heat waves. Such a price signal is a vast improvement over Central Hudson's current, excessively diluted approach.

We are concerned, however, about the timing of the implementation of the Staff proposal which would have the new pricing begin in May 2010. Because of a lag inherent in the NYISO's generation capacity pricing rules, this would make each customer's contribution to the NYISO's 2009 summer peak crucial. Given that the summer of 2009 is already underway, customers would not have time to understand their new generation capacity charge in time to react to a July or even August peak, and certainly not to a June peak. Accordingly, we direct that the existing rate remain in effect for an additional year, with the Staff proposal going into effect in time to be applied to each customer's contribution to the system's 2010 summer peak. This delay is unavoidable, given the current date, and it will give the Company ample time to inform customers of the new rate.

M. OTHER ISSUES

1. Low Income Programs

The RD recommended that the level of funding proposed by Staff for low income programs, approximately $1.8 million, be approved, but that the full amount be used for expansion of

Central Hudson's Enhanced Powerful Opportunities Program (EPOP). Staff had proposed using about $500,000 of the total to implement a monthly bill discount for customers receiving assistance through the Home Energy Assistance Program (HEAP). The RD reasoned that the funds would be better applied, from the standpoint of all ratepayers, if used to provide relief to customers who were in arrears in their payments, a condition of eligibility for EPOP.

Although no party takes exception to the RD's recommendations, Staff expresses strong disagreement with certain aspects of the reasoning underlying them. It argues that broad-based discount programs play an important role in a comprehensive low income program because they address the needs of customers who may be able to pay their utility bills, but only by diverting funds from other basic needs such as food and clothing. In fact, Staff argues, aiding only customers in arrears may perversely promote the ignoring of utility bills in favor of other expenses for which no assistance similar to EPOP is available. Finally, Staff says, whether low income customers are helped, rather than whether all ratepayers benefit, should be the primary consideration in the design of these programs.

Discussion - While Staff states that it is willing to accept the RD's recommendations, its comments make it clear that it continues to support the adoption of a bill discount, and we find its arguments to be persuasive. A low income program should not only provide assistance to customers who have been unable to pay their bills; it should also help those who are sacrificing to keep their payments current.

Elsewhere in this order, we approve increases in the customer charges for gas and electric service. These charges are particularly burdensome to low income customers because they are unrelated to usage and cannot be avoided. Therefore, we will modify the RD's recommendation by directing that the

$500,000 increase in the rate allowance for low income programs be used to fund a monthly discount of $5.00 for customers on whose behalf Central Hudson receives a HEAP payment. As is currently the case with the EPOP program, to the extent that the actual cost of the discount program varies from the authorized expenditure level, any excess costs incurred by the Company will be deferred for future recovery up to 15% of the program budget, and any under expenditures will be rolled over for program use in subsequent years.

2. Weather Normalization Clause (WNC)

Due to an ambiguity in the language of the RD, Central Hudson requests clarification that the recommended WNC will apply only from October 1 through May 31, as on other gas systems in the State.

Staff takes exception to the RD’s recommendation that the RDM and WNC adjustments be combined in a single line item on customer bills, suggesting that doing so will needlessly complicate reconciliation of the two.

Discussion - The Company's requested clarification is granted. We also clarify, in response to Staff’s concern, that the RDM and WNC adjustments are to be combined solely for the purpose of presenting a single number on customer bills. Otherwise, the adjustments are to be separately calculated and recorded by the Company and clearly broken out in any reports required by Staff for the purpose of auditing reconciliations.

3. Property Transfer

The RD recommended approval of an uncontested transfer of certain real property held by Central Hudson from a rate base account to a non-utility property account, with the net appraised value of the property to be deferred for ratepayer benefit. Staff seeks clarification that Central Hudson's erroneous filing of this accounting change as a request for approval of a transfer pursuant to PSL §70 does not relieve the Company of the obligation to make a §70 filing when it decides to sell the property to a third party.

Central Hudson responds that it has expressed its willingness to agree to a six-month holding period before it can transfer the property to a third party. This, it says, will ensure that the property is not "flipped" for a profit that should have belonged to ratepayers. If it is sold after that period, no §70 proceeding should be required.

Discussion - There is no magic to a six-month holding period that would convert the loss of a benefit to ratepayers into a matter of no concern to us. The issue would remain as to whether ratepayers received fair value for property they originally financed through their rates. A §70 filing need not be complex or burdensome and it will be required if and when this property is to be transferred.

III. UPDATES

With its Brief on Exceptions, Central Hudson provided numerous updates to previously submitted data. In general, these were authorized, are unobjectionable and are adopted. Staff, however, raised questions about a few of the updates in its Brief Opposing Exceptions. Those presenting issues requiring our decision have been addressed elsewhere in this order. The remainder, consisting of undisputed corrections or modifications, and revisions required for certain items because the numbers from which they are derived have been updated (e.g., the productivity adjustment, the allowance for payroll taxes, and I&IA expense) have been accepted and incorporated in our calculations.

VI. PETITION FOR DEFERRAL OF STORM RESTORATION COSTS

As we noted above, Central Hudson submitted a petition on January 2, 2009, requesting authorization to defer approximately $3.3 million in incremental storm restoration costs associated with a December 11, 2008, ice storm. We initiated Case 09-M-0004 to consider the petition, and notice of its pendency was published in the New York State Register on February 18, 2009, as required by the State Administrative Procedure Act. No comments in response to the notice were received.

In its Brief Opposing Exceptions, Staff reported that it had fully reviewed the facts underlying the Company's petition and had determined that they met the requirements of our three-prong test for deferral authorization.[30] After notifying the active parties in the rate proceeding of its intention to support the petition, Staff entered into a stipulation with the Company dated May 28, 2009, which recommends that we approve the requested deferral. Staff states that no party has expressed opposition to the terms of the stipulation.

Discussion - We approve the terms of the stipulation and grant the relief requested by Central Hudson in its deferral petition.

V. CONCLUSION

With the modifications described in the foregoing discussion, we adopt the recommendations of the April 10, 2009 Recommended Decision as to the rates, charges and terms of service of Central Hudson Gas & Electric Corporation for electric and gas service for the rate year commencing July 1, 2009.

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[30] See e.g., Case 01-G-1821, Central Hudson Gas & Electric Corporation, Order Regarding Deferred Accounting Plan for 2002 (issued October 25, 2002).

The Commission orders:

1. Central Hudson Gas & Electric Corporation is directed to file cancellation supplements, effective on not less than one day's notice, on or before June 26, 2009, cancelling the tariff amendments and supplements listed in Appendix I to this order.

2. Central Hudson Gas & Electric Corporation is directed to file, effective on not less than one day's notice on July 1, 2009, such further tariff revisions as are necessary to effectuate the provisions adopted by this order. The Company shall serve copies of its filing on all active parties in these cases. Any comments on the compliance filing must be received at the Commission's offices within 14 days of service of the Company's proposed amendments. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission.

3. The requirement of Section 66(12)(b) of the Public Service Law that newspaper publication be completed prior to the effective date of the proposed amendments directed in Clause 2 above is waived and the Company is directed to file with the Commission, not later than six weeks following the amendments' effective date, proof that a notice to the public of the changes made by the amendments has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments.

4. Central Hudson Gas & Electric Corporation shall file modifications to its tariff to implement effective August 1, 2009, voltage-specific electric loss factors determined in accordance with the findings of the Recommended Decision in this case.

5. Within 60 days following the issuance of this order, Central Hudson Gas & Electric Corporation shall submit a

plan for implementation of expansion of its Hourly Pricing Program. The plan shall be consistent with the recommendations set forth in the Recommended Decision, and a copy shall be served on all customers who will be added to the program as a result of the expansion.

6. The Retail Access Collaborative for Central Hudson Gas & Electric Corporation shall be continued. Staff shall schedule a meeting of the collaborative within 30 days after issuance of this order to consider the funding of retail access initiatives from the deferred balance attributable to the Competition Education Fund. Staff shall report the recommendations of the collaborative to us no later than six months following the initial meeting.

7. Within seven months following the issuance of this order, Central Hudson Gas & Electric Corporation shall perform a voltage-specific study of electric losses on its system, and shall file a report of its findings with the Commission. Copies of the report shall be served on all active parties to this proceeding.

8. Within fifteen days following the issuance of this Order, Central Hudson Gas & Electric Corporation is directed to file with the Secretary, and serve on all existing active parties, the June 15 Report and the supplemental information described in the body of this order to describe the manner in which it will implement the austerity adjustment described in the body of this order. Such filing will identify, <u>inter alia</u>, the capital and expense reductions Central Hudson Gas & Electric Corporation will be using to implement this austerity adjustment; the impacts, if any, on service quality or reliability which may result from these reductions; the future costs or increases in revenue requirement in later periods that may result from these reductions; and each capital and expense reduction that was considered, but not included, in the

austerity program and the reasons why the proposed reduction was not included. Any party may file and serve comments on the Company's filing within fifteen days after the filing is made.

9. The petition of Central Hudson Gas & Electric Corporation in Case 09-M-0004 is granted, and the Company is authorized to defer incremental restoration costs incurred as a result of the December 11, 2008, ice storm in the amount of $3,341,887.

10. Except as herein granted, all exceptions to the April 10, 2009, Recommended Decision are denied.

11. Except as specified herein, the April 10, 2009, Recommended Decision is adopted as part of this order.

12. The Secretary is authorized, upon a showing of good cause, to extend the filing deadlines set forth in the body of this order.

By the Commission,

(SIGNED) JACLYN A. BRILLING
Secretary

Filings by CENTRAL HUDSON GAS & ELECTRIC CORPORATION

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

Original Leaf No. 163.5.3
First Revised Leaves Nos. 169.2, 205.2
Second Revised Leaves Nos. 53.7, 135.1, 163.5.1
Third Revised Leaves Nos. 133, 163.5.2, 179, 196, 206.2, 218.2, 248, 272.7
Fourth Revised Leaves Nos. 107, 135, 211.1, 222.2, 231
Fifth Revised Leaves Nos. 136, 139, 165.1, 222.1, 262
Sixth Revised Leaves Nos. 134, 137, 169.1, 186.1, 206.1, 207, 218.1, 221, 226
Seventh Revised Leaves Nos. 109, 138, 184.2.1, 205.1, 206, 219
Eighth Revised Leaves Nos. 105, 165, 178, 185, 211, 217, 222
Ninth Revised Leaves Nos. 104, 169, 186, 205, 218, 220, 246, 247
Tenth Revised Leaf No. 246.1
Eleventh Revised Leaves Nos. 194, 210

Supplement Nos. 38, 39

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

Third Revised Leaves Nos. 121, 195
Fourth Revised Leaf No. 212
Fifth Revised Leaves Nos. 153, 171, 172
Sixth Revised Leaves Nos. 72, 151, 152 158
Seventh Revised Leaves Nos. 68, 181, 193
Eighth Revised Leaf No. 126.1
Ninth Revised Leaves Nos. 124.1, 188, 206
Tenth Revised Leaves Nos. 149, 186, 191
Eleventh Revised Leaf No. 126

Supplement Nos. 31, 32

Central Hudson Gas & Electric Corporation
Electric Operations Income Statement and Rate of Return Calculation
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted	Rate Increase	As Adjusted Rate Year Revenue Requirement
Operating Revenues						
Own Territory Delivery Revenues	$217,148	1	$1,309	$218,457	$38,011	$256,468
ECAM Revenues	0			0		0
SBC Surcharge Revenues	0			0		0
Deferred Revenues	0			0		0
Subtotal- Delivery Rates	$217,148		$1,309	$218,457	$38,011	$256,468
Resale Revenues	0					0
Other Operating Revenues	6,743			6,743	559	7,302
Total Operating Revenues	$223,891		$1,309	$225,200	$38,570	$263,770
Operating Expenses						
Production Maintenance	$516			$516		$516
Right of Way Maintenance-Transmission	1,592			1,592		1,592
Right of Way Maintenance-Distribution	9,792	2	471	10,263		10,263
Labor	43,893	3	1,665	45,558		45,558
Research and Development	1,927			1,927		1,927
Expenses Projected Based on Inflation	9,419	4	(86)	9,333		9,333
Miscellaneous General Expenses	2,926	5	(20)	2,906		2,906
Transportation Depreciation	1,736			1,736		1,736
Transportation Fuel	958	6	(330)	628		628
Fringe Benefits	5,670	7	(224)	5,446		5,446
Other Post Employee Benefits	3,713	8	1,952	5,665		5,665
Pension Plan	8,666	9	15,755	24,421		24,421
Contract Rents	1,885			1,885		1,885
Uncollectible Accounts	1,255	10	552	1,807	$312	2,119
Regulatory Commission Expenses	11,978	11	(9,999)	1,979		1,979
Information Technology Expense	2,006			2,006		2,006
Other Operating Insurance	1,247	12	(342)	905		905
Telephone	1,877	13	(17)	1,860		1,860
Legal Services	2,140	14	(22)	2,118		2,118
Special Services	1,251	15	(11)	1,240		1,240
Injuries and Damages	2,000	16	97	2,097		2,097
Storm Restoration	4,603	17	415	5,018		5,018
Environmental	364			364		364
Enhanced Powerful Opportunities Program	1,530			1,530		1,530
Expenses Allocated to Affiliates	(674)			(674)		(674)
Stray Voltage Testing	1,967			1,967		1,967
MGP Remediation Cost Recovery	2,399			2,399		2,399
Bill Print & Mail to Customer	538			538		538
Informational & Institutional Advertising	502	18	1	503	$27	530
Energy Efficiency Program	0			0		0
Transmission Enhanced Infrastructure Maintenance	700			700		700
Transmission Sag Mitigation	0			0		0
Economic Development	0			0		0
Competition Education Program	0			0		0
Productivity	(652)	19	(193)	(845)		(845)
Economic Austerity Imputation	0	20	(2,400)	(2,400)		(2,400)
Total Operating Expenses	$127,724		$7,264	$134,988	$339	$135,326
Other Deductions						
Property Taxes	$20,649	21	$489	$21,138		$21,138
Revenue Taxes	3,419	22	33	3,452	$945	4,396
Payroll Taxes	3,241	23	188	3,429		3,429
Other Taxes	1,403	24	118	1,521		1,521
Depreciation T&D	26,443	25	196	26,639		26,639
Total Other Deductions	$55,155		$1,024	$56,179	$945	$57,123
State Income Taxes	$1,040	26	($257)	$783	$2,647	$3,430
Federal Income Taxes	7,852	27	(1,179)	6,673	12,124	18,797
Total Income Taxes	$8,892		($1,436)	$7,456	$14,771	$22,227
Total Operating Revenue Deductions	$191,771		$6,851	$198,622	$16,054	$214,676
Net Operating Income	$32,120		($5,542)	$26,578	$22,516	$49,093
Rate Base	$671,462		$2,898	$674,360		$674,360
Rate of Return	4.78%			3.94%		7.28%

Central Hudson Gas & Electric Corporation
Electric Operations Federal Income Tax
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted	Rate Increase	As Adjusted
Income Before Federal Income Tax Excluding Interest Charges	$41,012		($6,978)	$34,034	$37,287	$71,320
Reconciling Amounts:						
Total Additional Income and Unallowable Deductions	$45,053		$196	$45,249		$45,249
Total Additional Deductions and Nontaxable Income	$79,944		($3,157)	$76,787		$76,787
Taxable Income before State Income Tax Deduction	$6,120		($3,625)	$2,495	$37,287	$39,782
Taxable Income after State Income Tax Deduction	$5,942		($3,368)	$2,574	$34,640	$37,214
Dividend Credit on Preferred Stock	($95)		$0	($95)	$0	($95)
Adjusted Taxable Income	$5,847		($3,368)	$2,479	$34,640	$37,119
Federal Income Tax						
Current Period Accrual	$2,047		($1,179)	$868	$12,124	$12,992
Additional Accrual	1			1		1
Total	$2,048		($1,179)	$869	$12,124	$12,993
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	$5,804		$0	$5,804		$5,804
Total Federal Income Taxes	$7,852		($1,179)	$6,673	$12,124	$18,797

Central Hudson Gas & Electric Corporation
Electric Operations Additional Income and Unallowable Deductions and
Electric Operations Additional Deductions and Nontaxable Income
For the Rate Year Ended June 30, 2010
($000)

Reconciling Items	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Additional Income and Unallowable Deductions:				
Depreciation - Central Hudson	$26,486		$196	$26,682
Transportation Depreciation	2,952			2,952
Officers Life Insurance Policy Premium	47			47
50 Percent Meal Disallowance	180			180
Avoided Cost Interest Capitalized	856			856
Contribution in Aid of Construction	1,409			1,409
Mortgage Bond Redempt Prem.	241			241
MGP SIR Costs & Recovery	0			0
OPEB Expense-Not Funded	4,035			4,035
Medicare Act Subsidy over/under collection	1			1
Officers Pension Expense FAS 87	1,127			1,127
Pension Expense-Not Deductible	7,719			7,719
Total	$45,053		$196	$45,249

Reconciling Items	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Additional Deductions and Nontaxable Income:				
Interest Expense	$19,942		($3,353)	$16,589
Depreciation - Central Hudson	45,144		196	45,340
Property Tax Accrued-Central Hudson	204			204
Vacation Accrual- Additional Tax Deduction	11			11
Officers Life Insurance Policy-Buildup CSV	34			34
Cost of Removal-Tax Basis	4,640			4,640
Repair Allowance	1,000			1,000
MGP SIR Costs & Recovery	0			0
OPEB Expense-Not Funded	2,050			2,050
OPEB Expense Medicare Act Subsidy	322			322
Deferred OPEB Over/Under Collected	1			1
Officers Pension Expense FAS 87	445			445
Pension Expense-Not Deductible	6,150			6,150
Deferred Pension Expense Over/Under Collected	1			1
Total	$79,944		($3,157)	$76,787

Central Hudson Gas & Electric Corporation
Electric Operations Federal Income Tax Deferred Items
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
FIT - Current Benefits Deferred:				
Depreciation-Central Hudson	$7,536			$7,536
Avoided Cost Interest Capitalized	(240)			(240)
Cost of Removal-Tax Basis	536			536
Repair Allowance	(47)			(47)
Contribution in Aid of Construction	(295)			(295)
Mortgage Bond Redemption Premium	(84)			(84)
MGP Site Removal Costs	0			0
OPEB Expense-Not Funded	(695)			(695)
Officers Pension Expense FAS 87	(239)			(239)
Pension Expense-Not Deductible	(549)			(549)
Amort. Deferred FIT Construction Charges	(109)			(109)
Amort. 81-82 ACRS Method Change	(10)			(10)
FIT - Current Benefits Deferred	$5,804		$0	$5,804

Central Hudson Gas & Electric Corporation
Electric Operations State Income Tax
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted	Rate Increase	As Adjusted
Federal Taxable Income	$41,012		($6,978)	$34,034	$37,287	$71,320
Reconciling Amounts:						
Total Additional Income and Unallowable Deductions	45,053		196	45,249	0	45,249
Total Additional Deductions and Nontaxable Income	79,944		(3,157)	76,787	0	76,787
Taxable Income before State Income Tax Deduction	$6,120		($3,625)	$2,495	$37,287	$39,782
NYS Adjustments to Federal Taxable Income:						
Additions:						
Federal Depreciation Deduction Transition Property	$10,184			$10,184		$10,184
Total Additions	$10,184		$0	$10,184	$0	$10,184
Subtractions:						
NYS Depreciation Deduction Transition Property	$13,696			$13,696		$13,696
Amortization - Regulatory Asset	103			103		103
Total Subtractions	$13,799		$0	$13,799	$0	$13,799
NYS Taxable Income	$2,505		($3,625)	($1,120)	$37,287	$36,167
State Income Tax						
Accrual For Current Period	$178		($257)	($79)	$2,647	$2,568
Total	$178		($257)	($79)	$2,647	$2,568
Current Benefits Deferred	$862		$0	$862		$862
Total State Income Taxes	$1,040		($257)	$783	$2,647	$3,430

Schedule 6

Central Hudson Gas & Electric Corporation
Electric Operations State Income Tax Deferred Items
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
SIT - Current Benefits Deferred:				
Depreciation-Central Hudson	$1,060			$1,060
Avoided Cost Interest Capitalized	(40)			(40)
Cost of Removal-Tax Basis	69			69
Repair Allowance	25			25
Contribution in Aid of Construction	(49)			(49)
Mortgage Bond Redemption Premium	(8)			(8)
MGP Site Removal Costs	0			0
OPEB Expense-Not Funded	(92)			(92)
Officers Pension Expense FAS 87	(31)			(31)
Pension Expense-Not Deductible	(72)			(72)
SIT - Current Benefits Deferred	$862		$0	$862

Central Hudson Gas & Electric Corporation
Electric Operations Rate Base Summary
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Book Cost of Utility Plant	$1,026,574	28	$3,033	$1,029,607
Less: Accumulated Provision for Depreciation & Amortization	($325,432)	29	$85	($325,347)
Net Plant	$701,142		$3,118	$704,260
Noninterest-Bearing Construction Work in Progress	$34,336	30	$95	$34,431
Customer Advances for Undergrounding	($1,434)			($1,434)
Deferred Charges	$10,268		$0	$10,268
Accumulated Deferred Federal Taxes	($108,708)	31	($1,274)	($109,982)
Accumulated Deferred State Taxes	($5,735)		$0	($5,735)
Working Capital	$34,834	32	$959	$35,793
Unadjusted Rate Base	$664,703		$2,898	$667,601
Capitalization Adjustment to Rate Base	$6,759			$6,759
Rate Base	$671,462		$2,898	$674,360

Central Hudson Gas & Electric Corporation
Electric Operations Deferred Items - Rate Base
For the Rate Year Ended June 30, 2010
($000)

Deferred Charges:

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
MTA Tax	$787			$787
Unamortized Debt Expense	2,867			2,867
Unamortized Discount Long Term Debt	40			40
Deferred Revenues-Attachments Rents	(450)			(450)
Executive Deferred Compensation Plan	2,096			2,096
Unamortized Loss on Reacquired Debt	3,706			3,706
Preferred Stock Costs & Redemption Premium	1,222			1,222
Total Deferred Charges	$10,268		$0	$10,268

Accumulated Deferred Federal Taxes

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Investment Tax Credit	($1,046)			($1,046)
Contributions in Aid of Construction	3,989			3,989
Unbilled Revenue	9,144			9,144
Construction Overheads	(566)			(566)
MTA Tax	(276)			(276)
Deferred Avoided Cost Interest Capitalized	1,202			1,202
Deferred Revenues- Attachment Rents	157			157
Bonds Redeemed	(785)			(785)
Cost of Removal	(2,285)			(2,285)
Repair allowance	(10,294)			(10,294)
Normalized Depreciation	(110,524)	32	(1,274)	(111,798)
ACRS Method Change	(18)			(18)
Use of Customer Benefit Acct-Capital Reliability Program	1,593			1,593
MACRS - Capital Reliability Program	1,001			1,001
Total Deferred Taxes	($108,708)		($1,274)	($109,982)

Accumulated Deferred State Income Taxes

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Normalized Depreciation	($6,092)			($6,092)
MTA Tax	(6)			(6)
Deferred Avoided Cost Interest Capitalized	90			90
Deferred Revenues- Attachment Rents	21			21
Bonds Redeemed	(84)			(84)
Cost of Removal	(302)			(302)
Repair Allowance	(855)			(855)
Contributions in Aid of Construction	422			422
Unbilled Revenue	648			648
Use of Customer Benefit Acct-Capital Reliability Program	222			222
MACRS - Capital Reliability Program	201			201
Rate Base Credit	0			0
MGP Site Costs	0			0
Total Deferred Taxes	($5,735)		$0	($5,735)

Central Hudson Gas & Electric Corporation
Electric Operations Working Capital - Rate Base
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Materials and Supplies				
Other Material and Supplies	$6,146			$6,146
Prepayments				
Prepaid Property Taxes	$6,256			$6,256
Prepaid Insurance	1,076			1,076
Other Prepayments	1,815			1,815
Prepayments Working Capital	$9,147		$0	$9,147
Operation and Maintenance				
Cash Working Capital	$19,541		$959	$20,500
Total Working Capital	$34,834		$959	$35,793

Central Hudson Gas & Electric Corporation
Electric Operations Capital Structure
For the Rate Year Ended June 30, 2010
($000)

	Amount	Adj. No.	%	Cost Rate	Weighted Cost	Pretax
Long Term Debt	$451,964		49.77%	4.86%	2.42%	2.42%
Customer Deposits	$8,269		0.91%	4.85%	0.04%	0.04%
Preferred Stock	$21,027		2.32%	5.05%	0.12%	0.20%
Common Equity	$426,774		47.00%	10.00%	4.70%	7.78%
Total	$908,034		100.0%		7.28%	10.44%

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Interest deduction				
Rate Base	$671,462		$2,898	$674,360
Weighted cost of long term debt	2.97%			2.46%
Total interest - tax deduction	$19,942		($3,353)	$16,589

Central Hudson Gas & Electric Corporation
Electric Operations Revenue Requirement Calculation
For the Rate Year Ended June 30, 2010
($000)

	Adj. No.			
Net Income after Rate Increase		$49,093	$674,360	7.28%
Net Income before Rate Increase		$26,578		
Net Income Increase		22,516		
Retention Factor		0.5923		
Revenue Increase Required		$38,011		
Revenue Increase Required(to I/S)		$38,011		
Revenue Increase Required		$38,011		
Uncollectibles		$312		
Revenue Taxes		$945		
Informational Advertising		$27		
Finance Charge		$559		
Retention Factor				
Additional Revenue Requirement		1.0000		
Less: Revenue Tax		0.02485		
Uncollectibles		0.0082		
Informational Advertising		0.0007		
Finance Charge		-0.0147		
Operating Income subject to FIT		0.9809		
Less: FIT		0.3433		
Less: SIT		0.0453		
Net Operating Income		0.5923		

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Electric Operations Commission Adjustments
For the Rate Year Ended June 30, 2010
($000) | Schedule 12
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Adj. No.	Explanation		
	Revenues		
1	Update sales forecast to reflect 10 year average	$	1,309
	Operation & Maintenance Expenses		
2	Right of Way Maintenance To reflect updated ROW Distribution line clearing estimates	$	471
3	Labor To reflect an employee count of 840 employees and latest known premium pay percentages	$	1,665
4	Expenses Projected Based on Inflation Updated for the latest GDP factors	$	(86)
5	Miscellaneous General Expense Updated for the latest GDP factors	$	(20)
6	Transportation Fuel Updated for the latest known prices applied to historic year volumes escalated at latest GDP factors	$	(330)
7	Fringe Benefits Update Fringe Benefits for latest twelve months actual medical premiums, claim activity & employee contributions and latest twelve months actual group life insurance premiums & employee contributions and 840 employee count	$	(224)
8	Other Post Employment Benefits Update for latest known actuarial estimate	$	1,952
9	Pension Expense Update for latest known actuarial estimate	$	15,755
10	Uncollectible Accounts Update uncollectible accounts for latest known twelve months of activity	$	552
11	Regulatory Commision Expense Update for latest known PSC assessment (Excludes new provisions to 18a Assessment)	$	(9,999)
12	Other Operating Insurance Updated for latest twelve months actual All Risk Insuarnce premiums, latest twelve months of D&O Insurance premiums and latest GDP factors and allocate only 1/2 of the premium to ratepayers	$	(342)
13	Telephone Expense Updated for the latest GDP factors	$	(17)
14	Legal Services Updated for the latest GDP factors	$	(22)
15	Special Services Updated for the latest GDP factors	$	(11)
16	Injuries & Damages Updated for latest twelve months actual Workers Comp and the four-year average of claims paid, latest twelve months of Excess Liability Insurance premiums, latest twelve months of personal & property damage, and latest GDP factors.	$	97
17	Storm Restoration Expense Updated for latest known twelve-month storm restoration expense excluding incremental expense associated with 12-11-08 ice storm in development of 4-year average	$	415
18	Informational & Institutional Advertising Track impact on changes to total operating revenues	$	1
19	Productivity To reflect changes to labor, fringe benefits, pensions, OPEBS, and payroll taxes	$	(193)
20	Economic Austerity Imputation To reflect austerity measures	$	(2,400)
	Other Deductions		
21	Property Taxes Update for latest known assessments	$	489
22	Revenue Taxes To track Staff's changes to operating revenues	$	33
23	Payroll Taxes To reflect the impact of the change to the company's employee count	$	188
24	Other Taxes To reflect lastest known sales and use tax	$	118
25	Depreciation T&D To reflect corrected depreciation expense	$	196
	Taxes		
26	State Income Taxes To track the impact of Staff's adjustments on State Income Taxes	$	(257)
27	Federal Income Taxes To track the impact of Staff's adjustments on Federal Income Taxes	$	(1,179)

($000)

Adj. No.	Explanation		
	Rate Base		
28	Impact of the change in capitalized Pension and OPEBs on Utility Plant	$	3,033
29	Update Rate Base Depreciation Reserve to changes to Commons ASL	$	85
30	Impact of the change in capitalized Pension and OPEBs on Non-interest-Bearing Construction Work in Progress	$	95
31	Update average deferred FIT on Normalized Depreciation for the additional Bonus Deprecation from the 2009 ARRA	$	(1,274)
32	Track impact on Rate Base Working Capital for changes to O&M	$	959

Central Hudson Gas & Electric Corporation
Gas Operations Income Statement and Rate of Return Calculation
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted	Rate Increase	As Adjusted Rate Year Revenue Requirement
Operating Revenues						
Own Territory Delivery Revenues	$52,411	1	$445	$52,856	$13,646	$66,502
GSC Revenues	0			0		0
Subtotal- Delivery Rates	$52,411		$445	$52,856	$13,646	$66,502
Resale Revenues	0			0		0
Interruptible Services	1,950			1,950		1,950
Other Operating Revenues	1,063			1,063	266	1,329
Total Operating Revenues	$55,424		$445	$55,869	$13,912	$69,781
Operating Expenses						
Labor	$10,463	2	$397	$10,860		$10,860
Research and Development	359			359		359
Expenses Projected Based on Inflation	3,170	3	(29)	3,141		3,141
Miscellaneous General Expenses	577	4	(3)	574		574
Transportation Depreciation	347			347		347
Transportation Fuel	197	5	(68)	129		129
Fringe Benefits	1,250	6	(51)	1,199		1,199
Other Post Employee Benefits	835	7	439	1,274		1,274
Pension Plan	1,903	8	3,543	5,446		5,446
Environmental	46			46		46
Contract Rents	131			131		131
Uncollectible Accounts	626	9	205	831	$209	1,040
Regulatory Commission Expenses	2,737	10	(2,285)	452		452
Information Technology Expense	358			358		358
Other Operating Insurance	189	11	(60)	129		129
Telephone	289	12	(2)	287		287
Legal Services	606	13	(9)	597		597
Special Services	356	14	(3)	353		353
Injuries and Damages	417	15	12	429		429
Enhanced Powerful Opportunities Program	270			270		270
Expenses Allocated to Affiliates	(119)			(119)		(119)
MGP Remediation Cost Recovery	416			416		416
Informational & Institutional Advertising	72			72	$5	77
Bill Print & Mail to Customer	95			95		95
Excess Cost of Removal	286	16	83	369		369
Gas Leak Repairs - Distribution Main	1,502			1,502		1,502
Energy Efficiency Program	0			0		0
Economic Development	0			0		0
Competition Education Program	0			0		0
Recovery of Net Regulatory Assets	4,224	17	330	4,554		4,554
Productivity	(152)	18	(44)	(196)		(196)
Economic Austerity Imputation	0	19	(600)	(600)		(600)
Total Operating Expenses	$31,450		$1,855	$33,306	$214	$33,520
Other Deductions						
Property Taxes	$5,596	20	$160	$5,756		$5,756
Revenue Taxes	989	21	13	1,002	$406	1,408
Payroll Taxes	729	22	42	771		771
Other Taxes	237	23	(37)	200		200
Depreciation T&D	7,184	24	155	7,339		7,339
Total Other Deductions	$14,735		$333	$15,068	$406	$15,474
State Income Taxes	$347	25	($58)	$289	$944	$1,233
Federal Income Taxes	2,161	26	(266)	1,895	4,322	6,217
Total Income Taxes	$2,508		($324)	$2,184	$5,266	$7,450
Total Operating Revenue Deductions	$48,693		$1,865	$50,558	$5,887	$56,444
Net Operating Income	$6,731		($1,420)	$5,311	$8,026	$13,337
Rate Base	$182,884		$322	$183,206		$183,206
Rate of Return	3.68%			2.90%		7.28%

Central Hudson Gas & Electric Corporation
Gas Operations Federal Income Tax
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted	Rate Increase	As Adjusted
Income Before Federal Income Tax Excluding Interest Charges	$9,239		($1,744)	$7,495	$13,291	$20,787
Reconciling Amounts:						
Total Additional Income and Unallowable Deductions	$15,050		$155	$15,205		$15,205
Total Additional Deductions and Nontaxable Income	20,412		(770)	19,642		19,642
Taxable Income before State Income Tax Deduction	$3,877		($819)	$3,058	$13,291	$16,350
Taxable Income after State Income Tax Deduction	$3,616		($761)	$2,855	$12,347	$15,203
Dividend Credit on Preferred Stock	($32)		$0	($32)	$0	($32)
Adjusted Taxable Income	$3,584		($761)	$2,823	$12,347	$15,171
Federal Income Tax						
Current Period Accrual	$1,254		($266)	$988	$4,322	$5,310
Total	$1,254		($266)	$988	$4,322	$5,310
Total Provision for Deferred Income Tax Accounts 410.1 & 411.1	$907		$0	$907		$907
Total Federal Income Taxes	$2,161		($266)	$1,895	$4,322	$6,217

Central Hudson Gas & Electric Corporation
Gas Operations Additional Income and Unallowable Deductions
Gas Operations Additional Deductions and Nontaxable Income
For the Rate Year Ended June 30, 2010
($000)

Reconciling Items	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Additional Income and Unallowable Deductions:				
Depreciation - Central Hudson	$7,184		$155	$7,339
Transportation Depreciation	521			521
Residual Gas Deferred Balance	4,205			4,205
Officers Life Ins Policy Premium	8			8
50 Percent Meal Disallowance	32			32
Avoided Cost Interest Capitalized	89			89
Contribution in Aid of Construction	88			88
Mortgage Bond Redempt Prem.	81			81
MGP SIR Costs & Recovery	0			0
OPEB Expense-Not Funded	907			907
Officers Pension Expense FAS87	199			199
Pension Expense-Not Deductible	1,736			1,736
Total	$15,050		$155	$15,205

Reconciling Items	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Additional Deductions and Nontaxable Income:				
Interest Expense	$5,432		($925)	$4,507
Depreciation - Central Hudson	12,393		155	12,548
Property Tax Accrued-Central Hudson	33			33
Vacation Accrual- Additional Tax Deduction	2			2
Officers Life Ins Policy - Buildup CSV	6			6
Cost of Removal-Tax Basis	594			594
MGP SIR Costs & Recovery	0			0
OPEB Expense-Not Funded	450			450
OPEB Expense-Medicare Act Subsidy	72			72
Deferred OPEB Over/Under collected	1			1
Officers Pension Expense FAS87	79			79
Pension Expense-Not Deductible	1,350			1,350
Total	$20,412		($770)	$19,642

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Schedule 4

Central Hudson Gas & Electric Corporation
Gas Operations Federal Income Tax Deferred Items
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
FIT - Current Benefits Deferred:				
Depreciation-Central Hudson	$2,713			$2,713
Residual Gas Deferred Balance	($1,472)			($1,472)
Avoided Cost Interest Capitalized	(15)			(15)
Cost of Removal-Tax Basis	13			13
Contribution in Aid of Construction	35			35
Mortgage Bond Redemption Premium	(28)			(28)
MGP SIR Costs & Recovery	0			0
OPEB Expense-Not Funded	(160)			(160)
Officers Pension Expense FAS87	(42)			(42)
Pension Expense-Not Deductible	(135)			(135)
Amort 81-82 ACRS Method Change	(2)			(2)
FIT - Current Benefits Deferred	$907		$0	$907

Central Hudson Gas & Electric Corporation
Gas Operations State Income Tax
For the Rate Year Ended June 30, 2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted	Rate Increase	As Adjusted
Federal Taxable Income	$9,239		($1,744)	$7,495	$13,291	$20,787
Reconciling Amounts:						
Total Additional Income and Unallowable Deductions	$15,050		$155	$15,205		$15,205
Total Additional Deductions and Nontaxable Income	20,412		(770)	19,642		19,642
Taxable Income before State Income Tax Deduction	$3,877		($819)	$3,058	$13,291	$16,350
NYS Adjustments to Federal Taxable Income:						
Additions:						
Federal Depreciation Deduction Transition Property	$3,379			$3,379		$3,379
Total Additions	$3,379		$0	$3,379	$0	$3,379
Subtractions:						
NYS Depreciation Deduction Transition Property	$3,541			$3,541		$3,541
Amortization - Regulatory Asset	34			34		34
Total Subtractions	$3,575		$0	$3,575	$0	$3,575
NYS Taxable Income	$3,681		($819)	$2,862	$13,291	$16,154
State Income Tax						
Accrual For Current Period	$261		($58)	$203	$944	$1,147
Total	$261		($58)	$203	$944	$1,147
Current Benefits Deferred	$86		$0	$86		$86
Total State Income Taxes	$347		($58)	$289	$944	$1,233

Central Hudson Gas & Electric Corporation
Gas Operations State Income Tax Deferred Items
For the Rate Year Ended June 30,2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
SIT - Current Benefits Deferred:				
Depreciation-Central Hudson	$326			$326
Residual Gas Deferred Balance	($194)			($194)
Avoided Cost Interest Capitalized	(4)			(4)
Cost of Removal-Tax Basis	2			2
Contribution in Aid of Construction	3			3
Mortgage Bond Redemption Premium	(2)			(2)
MGP SIR Costs & Recovery	0			0
OPEB Expense-Not Funded	(21)			(21)
Officers Pension Expense FAS87	(6)			(6)
Pension Expense-Not Deductible	(18)			(18)
SIT - Current Benefits Deferred	$86		$0	$86

Schedule 7

Central Hudson Gas & Electric Corporation
Gas Operations Rate Base Summary
For the Rate Year Ended June 30,2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Book Cost of Utility Plant	$297,906	27	$767	$298,673
Less: Accumulated Provision for Depreciation & Amortization	($102,431)	28	$30	($102,401)
Net Plant	$195,475		$797	$196,272
Noninterest-Bearing Construction Work in Progress	$9,114	29	$24	$9,138
Customer Advances for Undergrounding	($1)			($1)
Deferred Charges	$2,956		$0	$2,956
Accumulated Deferred Federal Taxes	($33,391)	30	($688)	($34,079)
Accumulated Deferred State Taxes	($1,357)		$0	($1,357)
Working Capital	$7,953	31	$189	$8,142
Unadjusted Rate Base	$180,749		$322	$181,071
Capitalization Adjustment to Rate Base	$2,135			$2,135
Rate Base	$182,884		$322	$183,206

Central Hudson Gas & Electric Corporation
Gas Operations Deferred Items - Rate Base
For the Rate Year Ended June 30, 2010
($000)

Deferred Charges:

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
MTA Tax	$112			$112
Unamortized Debt Expense	905			905
Unamortized Discount Long Term Debt	13			13
Executive Deferred Compensation Plan	370			370
Unamortized Loss on Reacquired Debt	1,170			1,170
Preferred Stock Costs & Redemption Premium	386			386
MGP Site Costs	0			0
Total Deferred Charges	$2,956		$0	$2,956

Accumulated Deferred Federal Taxes

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Investment Tax Credit	($219)			($219)
Contributions in Aid of Construction	1,450			1,450
Unbilled Revenue	4,956			4,956
MTA Tax	(39)			(39)
Deferred Avoided Cost Interest Capitalized	296			296
Bonds Redeemed	(248)			(248)
Cost of Removal	(424)			(424)
Normalized Depreciation	(39,156)	28	($688)	(39,844)
ACRS Method Change	(7)			(7)
Total Deferred Taxes	($33,391)		($688)	($34,079)

Accumulated Deferred State Income Taxes

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Normalized Depreciation	($1,877)			($1,877)
Deferred Avoided Cost Interest Capitalized	17			17
Bonds Redeemed	(27)			(27)
Cost of Removal	(56)			(56)
Contributions in Aid of Construction	171			171
Unbilled Revenue	415			415
Total Deferred Taxes	($1,357)		$0	($1,357)

Central Hudson Gas & Electric Corporation
Gas Operations Working Capital-Rate Base
For the Rate Year Ended June 30,2010
($000)

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Materials and Supplies				
Other Material and Supplies	$1,234			$1,234
Prepayments				
Prepaid Property Taxes	$1,663			$1,663
Prepaid Insurance	190			190
Other Prepayments	320			320
Prepayments Working Capital	2,173		$0	$2,173
Operation and Maintenance				
Cash Working Capital	$4,546		$189	$4,735
Total Working Capital	$7,953		$189	$8,142

Schedule 10

Central Hudson Gas & Electric Corporation
Gas Operations Capital Structure
For the Rate Year Ended June 30, 2010
($000)

	Amount	Adj. No.	%	Cost Rate	Weighted Cost	Pretax
Long Term Debt	$451,964		49.77%	4.86%	2.42%	2.42%
Customer Deposits	$8,269		0.91%	4.85%	0.04%	0.04%
Preferred Stock	$21,027		2.32%	5.05%	0.12%	0.20%
Common Equity	$426,774		47.00%	10.00%	4.70%	7.78%
Total	$908,034		100.0%		7.28%	10.44%

	Per RD	Adj. No.	Commission Adjustments	As Adjusted
Interest deduction				
Rate Base	$182,884		$322	$183,206
Weighted cost of long term debt	2.97%			2.46%
Total interest - tax deduction	$5,432		($925)	$4,507

Central Hudson Gas & Electric Corporation
Gas Operations Revenue Requirement Calculation
For the Rate Year Ended June 30, 2010
($000)

	Adj. No.			
Net Income after Rate Increase		$13,337	$183,206	7.28%
Net Income before Rate Increase		$5,311		
Net Income Increase		8,026		
Retention Factor		0.5882		
Revenue Increase Required		$13,646		
Revenue Increase Required(to I/S)		$13,646		
Revenue Increase Required		$13,646		
Uncollectibles		$209		
Revenue Taxes		$406		
Informational Advertising		$5		
Finance Charge		$266		
Retention Factor				
Additional Revenue Requirement		1.0000		
Less: Revenue Tax		0.0298		
Uncollectibles		0.0153		
Informational Advertising		0.0004		
Finance Charge		-0.0195		
Operating Income subject to FIT		0.9740		
Less: FIT		0.3409		
Less: SIT		0.0450		
Net Operating Income		0.5882		

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Central Hudson Gas & Electric Corporation
Gas Operations Commission Adjustments
For the Rate Year Ended June 30, 2010
($000)

Adj. No.	Explanation		
	Revenues		
1	Update sales forecast to reflect 10 year average	$	445
	Operation & Maintenance Expenses		
2	Labor To reflect an employee count of 840 employees and latest known premium pay percentages	$	397
3	Expenses Projected Based on Inflation Updated for the latest GDP factors	$	(29)
4	Miscellaneous General Expense Updated for the latest GDP factors	$	(3)
5	Transportation Fuel Updated for the latest known prices applied to historic year volumes escalated at latest GDP factors	$	(68)
6	Fringe Benefits Update Fringe Benefits for latest twelve months actual medical premiums, claim activity & employee contributions and latest twelve months actual group life insurance premiums & employee contributions and 840 employee count	$	(51)
7	Other Post Employment Benefits Update for latest known actuarial estimate	$	439
8	Pension Expense Update for latest known actuarial estimate	$	3,543
9	Uncollectible Accounts Update uncollectible accounts for latest known twelve months of activity	$	205
10	Regulatory Commision Expense Update for latest known PSC assessment (Excludes new provisions to 18a Assessment)	$	(2,285)
11	Other Operating Insurance Updated for latest twelve months actual All Risk Insuarnce premiums, latest twelve months of D&O Insurance premiums and latest GDP factors and allocate only 1/2 of the premium to ratepayers	$	(60)
12	Telephone Expense Updated for the latest GDP factors	$	(2)
13	Legal Services Updated for the latest GDP factors	$	(9)
14	Special Services Updated for the latest GDP factors	$	(3)
15	Injuries & Damages Updated for latest twelve months actual Workers Comp and the four-year average of claims paid, latest twelve months of Excess Liability Insurance premiums, latest twelve months of personal & property damage, and latest GDP factors.	$	12
16	Excess Cost of Removal To reflect changes to expensing the excess negative net salvage	$	83
17	Recovery of Net Regulatory Assets Update for latest projected Gas Offset List balances to be recovered over a 5-year period	$	330
18	Productivity To reflect changes to labor, fringe benefits, pensions, OPEBS, and payroll taxes	$	(44)
19	Economic Austerity Imputation To reflect austerity measures	$	(600)
	Other Deductions		
20	Property Taxes Update for latest known assessments	$	160
21	Revenue Taxes To track Staff's changes to operating revenues	$	13
22	Payroll Taxes To reflect the impact of the change to the company's employee count	$	42
23	Other Taxes To reflect lastest known sales and use tax	$	(37)
24	Depreciation T&D To reflect corrected depreciation expense	$	155
	Taxes		
25	State Income Taxes To track the impact of Staff's adjustments on State Income Taxes	$	(58)
26	Federal Income Taxes To track the impact of Staff's adjustments on Federal Income Taxes	$	(266)

Central Hudson Gas & Electric Corporation
Electric Operations Staff Adjustments
For the Rate Year Ended June 30, 2010
($000)

Adj. No.	Explanation		
	Rate Base		
27	Impact of the change in capitalized Pension and OPEBs on Utility Plant	$	767
28	Update Rate Base Depreciation Reserve to changes to Commons ASL	$	30
29	Impact of the change in capitalized Pension and OPEBs on Non-interest-Bearing Construction Work in Progress	$	24
30	Update average deferred FIT on Normalized Depreciation for the additional Bonus Deprecation from the 2009 ARRA	$	(688)
31	Track impact on Rate Base Working Capital for changes to O&M	$	189