NEW YORK STATE
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company New York, Inc. for Electric Service	Case 07-E-0523

DIRECT TESTIMONY AND EXHIBITS OF

HELMUTH W. SCHULTZ, III, CPA

and

DONNA M. DeRONNE, CPA

ON BEHALF OF THE

NYS CONSUMER PROTECTION BOARD

Dated: September 7, 2007
Albany, New York

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INTRODUCTION

Q. What are your names, occupations and business address?

A. My name is Helmuth W. Schultz, III, I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory analyst in the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

I am Donna DeRonne, a Certified Public Accountant licensed in the State of Michigan. I am a senior regulatory consultant in the firm Larkin & Associates, PLLC, whose address was identified above.

Q. Please describe the firm Larkin & Associates, PLLC.

A. Larkin & Associates, PLLC, is a certified public accounting and regulatory consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates, PLLC has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

Q. Have you previously filed testimony with the New York State Public Service Commission?

A. Yes. We submitted joint testimony earlier this year in Case 06-G-1332, regarding Consolidated Edison Company of New York, Inc.'s ("Con Edison" or "Company") natural gas operations. Ms. DeRonne also filed testimony in Case 05-E-1222, regarding New York State Electric & Gas Corporation, Case 06-G-1185 regarding the Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York, and Case 06-G-1186 regarding KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island.

Q. Have you prepared attachments describing your qualifications and experience?

A. Yes. We have included Attachments I and II, which are summaries of our regulatory experience and qualifications.

Q. What is the subject of your testimony?

A. We are testifying concerning Con Edison's May 4, 2007, rate filing for its electric operations.

Q. Do you have any exhibits supporting your testimony?

A. Yes. We have two exhibits. Exhibit___(LA), contains Schedules 1 through 8. Schedule 1 presents the impact on revenue requirement resulting from each of the adjustments we are recommending in this testimony. In determining the revenue requirement impact, we used the rate of return requested by the Company and its proposed revenue conversion factor. This does not, in any way, mean that we support the rate of return or revenue conversion factor incorporated in Con Edison's filing. Schedules 2 - 8 support several of our proposed adjustments to the Company's filing.

Exhibit___(LA2), Schedule 1 consists of a list of all information responses that we reference in this testimony and the corresponding page number of our testimony. Exhibit___(LA2), Schedule 2 consists of the actual responses to those information requests.

Q. On whose behalf are you appearing?

A. Larkin & Associates, PLLC was retained by the New York State Consumer Protection Board ("CPB").

GENERAL OVERVIEW

Q. Do you have any general observations regarding the Company's filing?

A. Con Edison's filing reflects significant increases in proposed spending on various operations and maintenance categories when compared to the limited historical information made available by the Company. In many cases, the Company, in its filing and in their responses to discovery, failed to provide adequate supporting documentation for the requested expenses in the rate year. In addition, the filing itself lacks proper organization and cross referencing that would facilitate review by the

Commission, Staff of the Department of Public Service ("DPS Staff") and interveners.

Q. What do you mean when you said that the historical information was limited?

A. In numerous requests, the Company was asked to provide comparable historic costs for the period 2002-2006. Except for one instance of which we are aware where historical cost information was provided, the Company only provided the information for 2004-2006. In some cases, even that limited historical cost information was not provided. It is not appropriate for the Company to limit the scope of review by those charged with the responsibility of analyzing the Company's request for an increase in rates.

Q. Why is it necessary to have the five years of information you requested?

A. Five years of information provides an opportunity to evaluate spending over a period of time in which fluctuations in any one year or two can be identified. It also allows for a comparison of requested costs to historical data to assess whether the request is reasonable. In fact, a number of jurisdictions use five or more years of data to develop an average for expenses such as uncollectibles, storms and tree trimming, which are then used in determining the utility's revenue requirement.

In our review of the DPS Staff report in Case 06-E-0894 concerning the extended outage in July 2006 in Con Edison's Long Island City Network, we noted that five years of cost data were analyzed. This amount of information greatly helped DPS Staff and CPB in that case, to analyze Con Edison's O&M expense levels – which remained relatively flat over the 2001 to 2005 period. This is an important observation when assessing changes in cost. When a comparison is made of the 2004-2006 costs, the 2007 budget and the rate year request for many of the costs in the filing, we note that the rate year costs spike significantly. An example of this comparison is shown on Exhibit___(LA), Schedule 2. This raises a concern because the Company's testimony emphasizes the need for an increase, yet the historical costs do not reflect an annual increase of the magnitude proposed by the Company. Further, even the budgeted costs do not reflect the increase that is proposed for the rate year.

Q. Could you explain your statement that the Company failed to supply supporting documentation?

A. Supporting documentation to an analyst, is a document that can substantiate a claim and/or an expense. The Company's filing and responses to discovery consistently include only a description that sometimes is accompanied with numbers and/or a calculation. There is a difference between supporting documentation (i.e., invoices, quotes, studies, etc.) and numbers on a piece of paper and/or a calculation. A calculation in many cases is helpful but does not constitute supporting documentation.

Even the Company's workpapers lacked supporting documentation for costs. A common example of what was included in a workpaper that purportedly supported the Company's request is a line that identified the cost as labor, accounts payable, materials, etc. and then a number. In our opinion, that does not constitute an acceptable level of support for costs within the filing. The lack of detail in the Company's workpapers is only exacerbated when the Company's response to a request for supporting documentation consists only of an explanatory paragraph and/or a calculation.

Q. Please elaborate on your statement that the filing lacked organization and cross referencing?

A. The Company's testimony often includes a discussion of an issue and refers to an exhibit. Then, that discussion changes to another topic and another exhibit, only to come back and again discuss another topic on the initial exhibit discussed. A prime example of this is the Infrastructure Investment Panel (IIP) testimony. The IIP testimony, at pages 29-35, discusses staffing and refers to Exhibit__ (IIP-3) and, on page 180, there is a discussion regarding telecommunications that is identified with Exhibit__ (IIP-3). Sandwiched in between pages 29 and 180 are discussions on costs reflected on Exhibit__ (IIP-6) and Exhibit__ (IIP-8).

Attempts to tie the respective exhibits to the Company's lead schedules (i.e. Exhibit__ (AP-5), Schedule 6) are frustrated because the lead schedules contain a reference only to the applicable witness. The absence of cross references to information makes it more difficult for the Commission and parties to focus on specific topics during their review. Better organization and cross referencing in the Company's filing could result in less discovery, a better understanding by all parties of its request, and a more efficient use of the resources of the Commission, DPS Staff and intervenors.

LABOR

Q. Do you have any concerns with the labor (payroll) expense reflected in the Company's request?

A. Yes. The $560,918,000 of projected payroll in the rate year reflects a net increase of 17.7%, or $84,285,000 over the test year payroll expense of $476,633,000. This increase reflects the impact of additional employees, pay raises, increased overtime and a generous compensation program for non-union employees. We are concerned with the Company's proposed normalization adjustment, the amount of payroll added for program changes, the compensatory pay, the escalated test year overtime and the variable pay.

Q. How did the Company determine its labor dollars?

A. The Company began with the test year labor expense of $476,633,000 and first increased it by $3,372,000 to reflect normalization adjustments. Then, the Company added $49,001,000 of program changes, escalation of $33,804,000 and finally, reduced the labor by $1,892,000 for cost savings associated with the implementation of the AMR/AMI (Automatic Meter Reading) System.

Q. What are the normalization adjustments?

A. The normalization adjustments include an increase to test year labor for positions filled during the year, for which a full year of compensation is not reflected in the test year. It also represents compensation for positions that are vacant as of the end of the test year. These adjustments have not been sufficiently justified by the Company and are not considered to be appropriate.

Q. Why did you state that the Company has not sufficiently justified the normalization adjustment?

A. The Company's testimony on this issue is very limited and the workpapers lack sufficient detail and/or justification. The testimony states the added dollars are for vacant positions, or positions that were filled during the year. The workpapers, in some cases, only show a description and a dollar amount, and in other cases there is a summary of the jobs that need to be filled with the associated dollar requirement.

Q. Why is the adjustment not considered to be appropriate?

A. The Company fails to reflect the fact that in the test year, vacancies occurred and an adjustment wasn't made to remove the labor dollars for employees that left during the test year. Next, the Company fails to adjust for vacancies that will occur in the rate year. The normalization proposed by the Company is strictly one sided.

Q. Are you recommending an adjustment to the labor normalization?

A. Yes. The only costs related to labor normalization that could reasonably be considered to be justified are the shared services and finance and auditing costs. However, we are recommending only 75% of the normalization adjustment of $1.216 million for shared services and finance, or $912,000, be allowed. This is because of the Company's failure to make an adjustment for vacancies that have occurred, or will occur. Therefore, we recommend that the Company's normalization adjustment of $3,372,000 be reduced by $2,460,000 ($3,372,000 - $912,000).

Q. Could you explain the Company's proposed program change adjustment?

A. The Company has requested the addition of numerous positions to accommodate its proposed changes in operations. These changes would affect seven major account groups and multiple subgroups within the various major account groups. However, it is not clear how many additional employees are being requested to fulfill the proposed program change requirements. CPB Information Request ("IR") 1(o) and DPS Staff IR137 sought the number of positions, their respective cost and the hiring status of the requested positions included in the Company's proposal for $49,001,000 for program changes. The Company's response was "See workpapers associated with the various program changes for supporting documents" and the attached schedules. The attachments to the response did not provide the requested information and the workpapers lacked any type of organization, indexing, or summary to sufficiently and/or reasonably ascertain what was requested. As an illustration, I have attached as Exhibit___(L&A), Schedule 3, a common document that was included in the numerous workpapers filed by the Company. This document includes an amount designated as a program change for labor. The detail requested by the CPB and DPS Staff was not provided.

Q. Does the Company's testimony provide sufficient information about the added positions?

A. No. The testimony actually provides contradictory information. The Accounting Panel testimony, at page 61, suggests a reduction in employees between the test year and the rate year. There is no indication that the Company has reflected an increase of a specific number of employees as part of the proposed program changes. Instead, the Company's testimony on program changes was distributed to various witnesses, it was very broad and lacked sufficient detail to cross reference the testimony to either the witnesses' attached exhibits, or to workpapers. In fact, a number of the exhibits listed costs that were not described in testimony at all. When questioned about select costs that could not be traced to testimony the Company stated the justification was in the workpapers, which as explained above, generally lack organization, detail and indexing.

Q. What about Company Exhibit__JM-2?

A. That exhibit summarizes employee changes in 2008, 2009 and 2010. The changes are not specific to the rate year and even if they were, they do not provide sufficient detail to reconcile and/or link the additions to the respective program change, or normalization adjustments proposed by the various Company witnesses. Overall, the Company's filing does not contain a clear presentation, with supporting detail, of these labor expense proposals. Moreover, the Company did not correct this deficiency when offered an opportunity by the CPB and DPS Staff in discovery.

Q. Are you recommending an adjustment to the labor dollars for program changes?

A. Yes. Because of the lack of support, we would typically recommend that only half of the proposed additional cost be allowed; however, because we have made various recommended adjustments, some of which include labor, we have limited our recommendation to 5% of the total program change request or $2.45 million ($49.001 x 5%). In addition to the lack of supporting detail, it is noteworthy that the Company has not demonstrated that it's very large proposed labor increases will in fact occur. We believe our recommended adjustment is reasonable given the facts that exist.

Q. What is compensatory time?

A. Compensatory time is authorized overtime for non-union personnel including management. It includes planned overtime, emergency overtime, holiday overtime and Pay Accrued Compensation Exception (PACE), or payment to certain management personnel. In 2004, compensatory pay was $23.316 million and in the 2006 test year, it was $33.233 million. The 42.5% increase in a two-year period is significant.

The Company has not adequately justified this large increase. In response to CPB IR 1(k), it stated: "The Company does not maintain data identifying compensatory time for electric, gas or steam operations individually". If the Company cannot separate the overtime to the different operations, there is virtually no way for it, or the Commission, to assess whether the compensatory time is justifiable, attributable to non-recurring events, and whether it should be paid by electric ratepayers.

Q. Does a similar problem exist with union overtime?

A. Yes. According to the response to CPB IR 1(aa), union overtime in 2004 was $92.181 million and $127.753 million in 2006, an increase of 38.6% over a two-year period. Again, this is significant and once again the Company did not provide adequate supporting information. Instead, it once again stated that "In allocating payroll to electric, gas and steam operations, the Company does not maintain data identifying the amount of overtime allocated to electric, gas and steam operations". If overtime is justified, it should be attributable to a specific cause and/or event. If that cause and/or event can be identified, the cost should be directly assigned to the operation that created the need for the overtime.

Effective management needs to analyze the cause of overtime and ensure that safe and reliable service is provided in a cost effective manner. Although overtime is an expected cost of operations, the level of overtime should not be simply accepted as part of normal operations and should be subject to review and control. The Company's inability to separate overtime among the various operations means it is essentially unable to know the cause and effect of any event on the cost of operations.

Q. Did you inquire as to why the overtime increased?

A. Yes. The Company's response to our request for an explanation of the increase between 2004 and 2006, was very general. The response stated that the increase in 2005 was due to the stray voltage program and increased repairs, and the 2006 increase was attributed to storms. The explanations suggest that the test year overtime does not reflect normal conditions and that an adjustment should be made to reduce the test year cost level.

Q. Do you recommend an adjustment to projected compensatory time and overtime costs for the rate year?

A. Yes. Two adjustments are required. The first adjustment removes the escalation applied to the $65.913 million of estimated electric operations' compensatory time and overtime expense in the test year. Eliminating the 6.39% escalation reduces payroll expense by $4.212 million. The estimated compensatory time and overtime is based on the 2006 total cost of $160.986 million, multiplied by the ratio of test year electric O&M expense of $476.633 million, to the total Company test year payroll of $1,164.126 million as shown on Company Exhibit__ (AP-5), Schedule 2, Page 1. This adjustment is necessary because in our judgment the test year overtime is excessive in comparison to historical overtime and we would not expect it to increase.

Q. What is the second adjustment for electric operations' compensatory time and overtime?

A. The second adjustment reduces the estimated electric operations' compensatory time and overtime of $65.913 million by 10%, or $6.591

million to reflect the fact that significant additions to the Company's work force are projected in the filing and to eliminate some of the extra overtime for unusual storms.

Q. What about the reduction to program changes and the productivity adjustment reflected in the filing?

A. The Company has requested a net increase of $47.223 million for additional personnel (i.e. program changes). We recommended a $2.45 million reduction for program changes in our earlier payroll discussion and will recommend an additional $19.958 million reduction for payroll related to other program changes later on in our testimony. The net increase allowed of $25.175 million for program changes is still significant enough to assume that the added employees would reduce the future overtime. The productivity reduction included in the filing by the Company is assumed to reflect technological advances as well as cost savings from improved efficiencies beyond overtime related activities.

Q. What is your concern with the Company's proposal regarding variable pay?

A. The Management Variable Pay program allows for payment of additional compensation to non-officer management employees on the presumption that it enhances corporate results. The first concern with the program is that according to the response to CPB IR 1(h), the program awards "management employees with at least satisfactory performance". However, base compensation for management employees should assume satisfactory performance. Variable pay, bonus pay, or incentive compensation should be only awarded for performance that is over and above that which is expected of an employee and that which results in increased benefits to shareholders and ratepayers alike.

A second concern with the response to CPB IR 1(h) is that it did not provide the information requested. The Company was asked to "provide any document that explains to employees what variable pay is and how it is determined". The Company provided an explanation that was very general, and no document was included as requested. The Company has failed to justify its variable pay program.

The arbitrary addition of 6% is not supported by even the Company's historical performance, or its assumptions that determine the variable pay rate. According to the response to CPB IR 1(g), the estimated target is 5.92 %, not 6%. Then, in response to CPB IR 31(f), the Company indicated that it did not achieve the target in one of three bands in 2005 and in all three bands in 2006. The requested information for 2004 was not provided. To assume a target payout in the rate year based on an arbitrary rate that exceeds the Company's projection and which is inconsistent with historical payouts is not appropriate.

Q. What adjustment are you recommending for variable pay?

A. According to the response to CPB IR 31(g), the test year includes actual payments under the variable pay program for the 2005 plan year. The payout was $23.262 million for Con Edison as a whole, including $10.532 million for electric operations. The test year was escalated by 6.39% or $672,995 for a rate year expense of $11.205 million. We are recommending the entire $11.205 million be disallowed because the Company has not provided justification for charging ratepayers this excessive compensation, there is no evidence providing any indication that ratepayers benefit from the program and the Company failed to submit the information requested for us to evaluate the appropriateness of this program.

Q. Please summarize your payroll recommended adjustments.

A. As shown on Exhibit___(LA), Schedule 4, the Company's payroll request should be reduced $2.46 million for unjustified normalization costs, $2.45 million for unidentifiable program changes, $10.803 million for excessive compensatory time and overtime and $11.205 million for unsupported variable pay, for a total reduction of $26.918 million.

EMPLOYEE WELFARE EXPENSE

Q. What concerns have you identified with the Company's request regarding employee benefits?

A. We believe that to the extent an adjustment is made to remove payroll dollars, a related adjustment should be made to reduce employee benefits. In addition, we note that while the various employee benefits increased by approximately 6%, the expense for group life insurance increased 22.6%. This change is significant.

Q. Why would group life insurance costs increase so much?

A. The Company records its annual expense net of any dividends received from its insurance provider, MetLife. When the costs were estimated for the rate year, the Company ignored the dividends and estimated the cost based on the gross premiums paid.

Q. Is that appropriate?

A. No. The Company typically receives a dividend, as indicated in the response to CPB IR 39(a). Over the five year period 2002-2006, the dividends averaged $928,487 a year. In reviewing the response, it was noticed that a discrepancy may exist in either the filing or the response. The response to CPB IR 15(b), states that the $1,496,093 on Exhibit__ (HJR-1) was the electric portion of premiums paid net of the dividends received. The response to CPB IR 39, indicates that group life insurance expense for electric operations in 2006 was $1,753,664 and the 2006 dividends in total were $1,140,585. If the 78.67% allocation to electric operations was applied to the 2006 dividends, the electric portion would be $897,298. The net expense for 2006 electric operations would then be $856,366 ($1,753,664 - $897,298). That $856,366 differs significantly from what the Company identified as the test year amount of $1,496,093 even if the Key Retired Officers Life and Dependant Life costs are included. We are concerned that the Company may be allocating the dividends differently than the premium costs.

Q. Should an adjustment be made to the rate year?

A. Yes. First, the electric operations' cost in total should be reduced $730,440 ($928,487 x 78.67%) to reflect the dividend for Group Life Insurance. The result is an adjusted benefit cost of $96.752 million. Next, the benefit cost should be reduced to reflect the reduction in employees and payroll. Using a 17.25% ratio of Welfare Benefit Expense to Payroll Expense, the projected benefit expense in the rate year of $97.482 million is reduced $5.373 million to $92,109 million. This calculation is shown on Exhibit___(LA) Schedule 4.

<u>INSURANCE</u>

Q. Are you recommending an adjustment to the Company's request for insurance expense?

A. Yes. We are recommending two different adjustments. First, the Company's assumption that there will be an increase in insurance expense is not supported by the historical trend. Further, the Company failed to supply supporting documentation to show that there will be an increase in premiums. Therefore, we recommend the $5.354 million added as a program change by the Company be disallowed.

The second adjustment removes $5.44 million of insurance for protecting directors and officers from any claims for inappropriate activities and/or decisions. There is no direct benefit of this expense to ratepayers and therefore, it should not be charged to ratepayers. The Company's rate year insurance expense should be reduced by a total of $10.794 million.

Q. What do you mean the historical trend does not support an increase in insurance?

A. The response to CPB IR 22(d), shows that the insurance expense in 2004 was $27.22 million, in 2005 the expense was $24.931 million, and in 2006 the expense was $24.071 million. Costs have declined each year since 2004 so it appears that a downward adjustment to the test year expense is warranted, rather than the increase proposed by the Company.

Q. Is it possible that the Company received notices that its premiums were increasing?

A. That is possible. However, the Company was requested in CPB IR 22(d) to provide supporting documentation to verify the cost increase reflected in the filing and its response did not provide such information. The Company had the opportunity to prove its case and failed to do so. Accordingly, the adjustment to reduce the cost back to the test year level should be made.

Q. Could you explain further why the directors and officers' liability insurance should be disallowed?

A. Yes. Directors and officers' liability insurance ("DOL") represents 22.6% of the total insurance expense for electric operations. This insurance is designed to protect directors and officers from inappropriate activities they may have participated in and/or from decisions that they made. Essentially, the cost of this insurance protects shareholders from their decision to appoint directors who are in turn responsible for hiring the officers of the Company. Generally, it is shareholders who will make a claim against the directors and/or officers, therefore, the insurance ultimately will provide protection to the shareholder. If a claim was to be made and a liability determined, the resulting proceeds would be paid to the shareholder(s) making that claim. The ratepayer receives nothing. Further, the ratepayer does not decide who is in charge at the Company, the shareholder does. Therefore, the shareholder should be responsible for costs associated with mitigating the risk of their decision.

Finally, the fact that this expense represents 22.6% of the total cost of corporate insurance (i.e. excluding employee health & welfare insurance) cannot be ignored. The significance of the cost for this coverage in relation to the insurance that covers plant and public liability has to be a concern.

Q. Have you litigated this issue before?

A. Yes. Years ago the issue was presented and rejected by a number of jurisdictions. Companies would often argue that without this insurance they would not be able to attract top quality management. The decisions at that time looked at the cost involved and essentially decided it was not a material cost issue.

Circumstances changed in 2001 and 2002 as a result of the discovery of numerous accounting and other corporate scandals. As a result, the cost of DOL insurance has increased significantly and has become a material cost. This increase is attributed to the fact that significant claims were made on these policies, greater risk was perceived and coverage was more extensive than before. Some neighboring jurisdictions, such as Vermont and Connecticut, have rendered decisions wherein a portion of the cost of DOL insurance has been disallowed.

Q. Is DOL insurance necessary to attract competent individuals?

A. Directors and officers are compensated for their time; they receive generous benefit packages, including generous stock options. If they are being paid by ratepayers for their competence, it is unreasonable for ratepayers to pay again, to insulate these individuals from their personal responsibility for inappropriate decisions. If Directors and Officers provide the performance for which ratepayers are paying, the level of insurance coverage should be minimized.

Even if DOL insurance is determined to be necessary to attract excellent employees, the benefit of the insurance goes to shareholders not ratepayers. Ratepayers should not be required to pay for something that does not provide a benefit to them, especially when the real beneficiary is the shareholders. The profit (i.e., the return on equity) allowed shareholders incorporates a risk factor and one risk is that management is competent. The cost of insurance to secure that competence is part of that risk.

MGP/SUPERFUND

Q. Why is there such a significant increase in the Company's expense for the MGP/Superfund?

A. Con Edison estimates that it will spend $189.8 million related to Manufactured Gas Plant ("MGP") site remediation and Superfund projects from April 2007 through March 2009. Of the $189.8 million requested, $149.394 million would be charged to electric operations. In its recent gas case, the Company estimated $128 million of total Company cost for a comparable period of time and $77.9 million of these expenses for the rate year that ended just six months prior to the period in this case.

The current balance of MGP/Superfund expenses that should be charged to ratepayers as of March 31, 2007, is $9.5 million. Based on rates currently in effect, only approximately $612,000 would remain to be recovered from ratepayers as of April 1, 2008, the date new rates are expected to go into effect. The Company's request is significant and it failed to provide sufficient justification for the increase.

Q. What do you mean that the Company failed to provide sufficient justification for the increase?

A. The Company was requested in CPB IR 22(f) to "provide all supporting workpapers and documentation for the calculation of the MGP/Superfund amount." That request also stated that "supporting documentation should also include any cost estimates received for the $189.8 million in projected spending". The response referred us to the Company workpapers provided with the filing. The workpapers show the $9.5 million beginning balance as of March 31, 2007, and documents to support that balance. In contrast, there were no documents showing and/or explaining how the $189 million estimate was derived. The only information on the $189 million estimate could best be characterized as "some numbers on a page."

Q. Is the amount of the request a concern?

A. Yes. The Company, in its recent gas case, estimated total Company MGP/Superfund costs for the rate years ending September 30, 2008, September 30, 2009, and September 30, 2010. Based on those estimates, the prorated total Company cost for the rate year ending March 31, 2009, would be $57.9 million. In this case, Con Edison is estimating a total Company cost of $112.927 million in the rate year. That is $55 million above its estimate only a short time ago, an increase of approximately 95%. It is interesting to note that Company workpapers in this filing indicated costs of $76.9 million for the year ending March 31, 2008. The gas case estimate, based on the more detailed workpapers supplied in that filing, indicated the costs for that same period would be $60.753 million, a difference of $16.1 million, or approximately 27%. This difference is not nearly as large as the difference in rate year estimates, which raises additional questions. It is also noteworthy that in both the electric and gas cases, the rate year costs spiked significantly when compared to the prior period estimate and the subsequent period estimates.

Q. Is there an expectation that some MGP/Superfund costs will be incurred in the rate year?

A. Yes. However, in ratemaking, there are requirements that must be met for a utility to recover its costs. One such requirement is that the Company has the burden of proof to show that the costs do exist or will exist and that the cost can be estimated. To meet that burden of proof, there is a known and measurable standard that needs to be applied. The type of cost must be known and measurable. To establish the existence of a cost, the Company has to provide <u>documented</u> evidence and to establish a cost, the Company must provide <u>documented</u> evidence of the cost estimate (emphasis added). The Company has identified sites in exhibits to Mr. Price's testimony. It has not provided support for MGP/Superfund costs projected in this case.

Q. Does the Company apply the known and measurable requirement in the filing?

A. Selectively, yes. The Company has included a number of program costs without providing supporting documentation; however, when asked about cost savings that would result, the Company replied in response to CPB IR 22(h), that the savings were not reflected because the program benefit was "neither certain nor quantifiable". That response suggests the Company is aware of the known and measurable standard.

Q. Are you recommending an adjustment?

A. Yes. The Company's estimate of MGP/Superfund costs has not been supported. We believe some support may exist, but it was not provided when requested. Mr. Price refers to a study in his testimony and the fact that there is an estimate for costs. However, the Company did not provide that study, or make the Company's assessment of its potential liability for those sites available for review when we requested supporting documentation. If the Company's auditor, or Internal Revenue Service requested supporting documentation, the Company would be required to provide a document that justifies the amount being analyzed. The Company should be required to provide similar justification to support a cost that it is requesting ratepayers to pay. Because the Company has failed to provide that justification, we are recommending that the entire $50.002 million included in the filing be disallowed.

Alternatively, if the Commission is convinced that the support for all or a portion of the Company's estimate of MGP/Superfund costs is adequate, it could establish a mechanism to begin to recover the documented costs attributable to electric operations. Any decision to commence such recovery, however, should be part of a comprehensive review by the Commission of the funds the Company actually spends on these projects. In no event, should ratepayers provide funding ostensibly for environmental cleanup efforts, which is not in fact spent for that purpose. Any such amounts should be returned, with interest, and used for the benefit of customers.

Moreover, for the reasons explained in the testimony of CPB witness Dr. Elfner, the recovery of documented environmental remediation costs in this proceeding should be over a period of 10 years, instead of the 3 years proposed by Con Edison.

Q. How will the Company recover the MGP/Superfund costs that it will incur, if its recommendation is not adopted?

A. That will ultimately depend on the Company establishing that the costs were incurred and were reasonable. If it means deferring the costs until some future date, then that is what should be done. The Company should not be allowed a blank check recovery for costs not yet incurred without having to provide any substantiation that the remediation is occurring and the costs being requested are supported and reasonable.

SUBSTATION OPERATIONS O&M PROGRAMS

Q. What changes are being requested for substation operations O&M?

A. The Company, on Exhibit__ (IIP-3), is requesting a 31% increase to the test year expense of $35.245 million, or an increase of $11.028 million. The increase consists of $6.728 million for labor and $4.3 million of other costs. General explanations of the cost and increases could be found in the Infrastructure Investment Panel testimony. However, the testimony was not in an organized manner and was not sufficiently detailed to provide justification for the requested cost increase. For example, two components of substation O&M, the SSO Staffing program and the Telecommunications program, were discussed, beginning on pages 29 and 180, respectively, with various other programs, such as System and Transmission Operations, sandwiched in between.

Q. Did the workpapers provide sufficient detail to justify the program requests?

A. No. The workpapers included general descriptions of the various programs, often very similar to the testimony, but there was no detail indicating how the costs were derived. The only cost information presented was a number. A worksheet attached to the limited written description would only indicate a number with a description, an example being “labor”, “on going,” or “accounts payable”.

Q. Did you ask for more information?

A. Yes. In CPB IR 8 and CPB IR 10, the Company was requested to provide additional information for the various programs within the Substation Operations O&M Program category. It was not totally responsive. For example, supporting documentation for the cost estimates for five of the programs was requested in CPB IR 8 and CPB IR 10 and the only information supplied were numbers, a reference to workpapers, or nothing at all. Again, when Con Edison referred to the workpapers, we could not locate documents that would support the cost estimate. As previously stated, supporting documentation is not just numbers on paper. Instead, it is a document, invoice, quote or study.

Q. Are you recommending an adjustment to Substation Operations O&M Program costs?

A. Yes. We are recommending that the Company's projection of substation operations O&M costs be reduced by $3.737 million due to the Company's failure to properly substantiate these costs. The adjustment removes $592,000 of program change labor costs and $3.145 million of unsupported other costs. The specific programs, as shown on Exhibit__ (LA), Schedule 5, page 1 of 3, are Telecommunications, Advanced Control Systems Group, Cable Cooling System maintenance, Dynamic Feeder Rating System and the Structural Integrity/Station Betterment program.

SYSTEM & TRANSMISSION O&M PROGRAMS

Q. Are there changes being requested for system and transmission operations?

A. Yes. The Company, on Exhibit__ (IIP-6), is requesting that test year expense of $9.66 million be increased by $7.375 million. The increase consists of $2.557 million for labor and $4.818 million for other costs. Again, general explanations of the cost and the increases could be found in the Infrastructure Investment Panel testimony for most of the programs. However, the testimony was scattered and did not sufficiently detail the changes to provide justification for the requested cost increase. No testimony was provided for the added personnel for New York Independent System Operator functions, Training for Emergency Central

Information Group and the Furnace Brook Lake Dam Maintenance program.

Q. Did the workpapers provide similar detail to that provided for Substations Operations O&M Programs?

A. Yes. The workpapers included general descriptions of the various programs, similar to the testimony, but again, there was no detail as to how the costs were derived. They did not contain sufficient support for the cost increases requested by the Company.

Q. Did you ask for more information for the System & Transmission Operations O&M Programs?

A. Yes. The Company was requested to provide additional information for the various programs within the System & Transmission Operations O&M Programs category, but it was not totally responsive. Supporting documentation for the cost estimates for five of the programs were requested and again, the information was not supplied. A question was asked about the pilot program costs in the test year for the PFT Patrols that were not reflected on the Company exhibit, and the Company indicated that the costs were reflected elsewhere. Also, there was no indication as to whether the pilot program costs were removed to avoid a double count.

Q. Do you have any other concerns about this projected expense?

A. Yes. In CPB IR 11(d), we asked why the cost of the Bird Discourager Program was not capitalized. The response indicated that the cost is capitalized if this equipment is installed when the tower is installed. Otherwise it is treated as O&M expense. The purported support for this determination is the Company's accounting procedures. Based on this interpretation, the Company could defer attaching plant that would normally be capitalized so it can be expensed and the cost recovery accelerated.

Another concern is that the Company has proposed a rate year expense of $1.2 million for the refurbishment of 90 manholes. In 2006, the Company performed this task on 97 manholes at a cost of $834,000. This specific unexplained increase in cost for what appears to be less maintenance, is a prime example as to why the Company should be required to provide documented justification for the cost it is requesting. The average cost of refurbishing manholes from 2004 through to 2006 was $9,923 per manhole. Each year from 2004 through 2006, the average cost for refurbishment declined. In 2004, it cost $12,793 per manhole and in 2006, it cost $8,598 per manhole for refurbishment. However, the Company's estimate for the rate year averages out to $13,333 per manhole. There is absolutely no justification for the $4,735 increase in cost per manhole between the test year and the rate year. The rate year cost is excessive and should be reduced. In response to a request for supporting information for the Manhole Inspection program in CPB IR 11(g), the Company provided a calculation that did not equal the requested cost. The calculation is not sufficient supporting documentation for the cost estimate. The CPB renewed our request for this information in CPB IR 36(b), and the Company supplied the same calculation in its response. This provides a further indication that the Company does not recognize the difference between supporting documentation and a calculation.

Finally, the Company has included $700,000 in the rate year for an option to join a consortium for purchasing and storing materials. It states that if the plan does not fully develop or proves to be unsuitable, the funding will be used for emergency training and training kits. This cost is not properly supported and is an example of the improper practice of “wish list” cost itemization to be included in rates. This open-ended request is not appropriate by any reasonable standard and should be summarily rejected.

Q. Please summarize your recommendation regarding the Company’s projected System & Transmission Operations O&M Program costs?

A. We recommend that the Company’s projections be reduced by $3.37 million because supporting documentation for certain projects was not supplied. In addition, we are recommending that the manhole refurbishment cost be reduced $426,180 to reflect the cost per manhole rate actually incurred in 2006. The Company's inability to substantiate costs included in the filing results in a total recommended reduction for this program of $3.796 million. A summary of the Company's request and our recommendations are shown on Exhibit___(LA), Schedule 5, page 2 of 3.

ELECTRIC OPERATIONS O&M PROGRAMS

Support Economic Growth

Q. Did you review the Company's testimony that explains why it believes the costs for programs supporting economic growth should be included in rates?

A. No. The Company did not provide testimony to explain the various programs within the caption "Support Economic Growth" on Company Exhibit__ (IIP-8). When asked in CPB IR 12(e) where these programs were discussed by Company witnesses, the Company simply stated "These programs are described in detail in the workpapers that were provided with the filing".

Q. Did you review the workpapers?

A. Yes. The Company is requesting some new programs and some added costs for doing tasks that are not currently being performed. It requests $1.445 million for program changes, $520,000 of which is for added personnel. The exact number of employees requested cannot be determined from the workpapers.

Q. Are you recommending an adjustment to the Company's request?

A. Yes. The Company's request may have some merit for some of the programs, but to assume that the programs will, in fact, occur and that they will provide a benefit to ratepayers, is premature and not substantiated. There is not sufficient information to even determine how the projected costs were developed and whether the estimates are reasonable. As shown on Exhibit___(LA), Schedule 5, page 3 of 3, we are recommending that 50% of the program change cost, or $722,000, be disallowed.

<u>Improve Reliability</u>

Q. What program costs is the Company requesting for reliability improvement?

A. The Company is requesting an increase of 245%, or $7.575 million over the test year expense of $3.094 million, for increasing repairs, inspections and maintenance to the system. Of the requested $10.669 million, only the $2.325 million for Unit Substation Repairs and Inspections is discussed in the Company's testimony. Two of the programs were described in the workpapers and the final program "Maintenance associated with capital work," which accounts for $5.488 million of the requested cost, could not be substantiated by the workpapers provided. For example, $1.446 million of the proposed maintenance cost was for “Network Transformer Replacement”. In reviewing the workpapers, we found no explanation as to how the cost estimate was developed, and no calculation. The requested cost is just a number on a piece of paper without any supporting documentation. The cost is not known and measurable and is considered questionable.

Q. Are there concerns with the cost requested?

A. The Unit Substation repairs and inspections costs are not normal maintenance. Over the last three years, the Company has averaged $240,000 a year in maintenance and for 2007, the Company budgeted $300,000. In the rate year, the costs are projected to be $2.325 million for special maintenance that is supposedly to be performed only once in the life of the respective units. The Company has projected that in 2010 and 2011, another $2.511 million will be spent in total. Clearly, to allow the one-time cost in the rate year would be inappropriate.

Q. What adjustment are you recommending to the rate year for the Unit Substation repairs and inspections?

A. We are recommending that the average of the costs forecast for the three years, be used for the rate year. That average is $1.512 million and would reduce the Company’s request by $813,000.

Q. What are you recommending for the various other costs listed under the caption "Improve Reliability"?

A. Given the lack of supporting detail and the less than sufficient justification that the costs, some of which could not be identified, will in fact be incurred, we are recommending that rates be set to reflect 50% of the $5.55 million of remaining requested program change costs or $2.775 million. The total reduction to the program cost in the Improve Reliability category would be $3.588 million ($2,775,000 + $813,000). The Company's request and our recommendations are shown on Exhibit___(LA), Schedule 5, page 3 of 3.

However, we understand that in some respects, the Company has substantial work to do to improve the reliability of its electric system. Therefore, if the Company prudently spends more on reliability-related electric O&M expenditures than the amount permitted in rates, it should be permitted to defer the difference, up to its projection of $10.699 million. Similarly, if it spends less than the amount reflected in rates, the difference should be deferred and used for the benefit of ratepayers.

<u>Public Safety and Environmental</u>

Q. What is the change that is being requested for the Public Safety and Environmental program?

A. The Company is requesting a 200% increase of $49.11 million from the test year expense level of $24.525 million. The primary drivers are underground inspections, overhead inspections, stray voltage testing and a vault cleaning program. We will discuss each of the individual programs that are primarily responsible for this significant increase.

<u>Five Year Overhead ("OH") Inspection Program</u>

Q. Did you review the Company's request for an increase of $5.443 million for overhead pole inspections?

A. We tried, but were unable to review the cost development in detail. The Company's request is significant because no costs for OH inspections were incurred in the test year. The Company's justification for the absence of activity in the test year is that a complete inventory was performed in 2005 so no inspections were planned for 2006 and 2007.

According to the workpapers for OH inspections, the electric facilities are to be inspected once every five years. It is presumed the justification included in the workpapers applied to the OH facilities despite the fact that the rationale is the exact same justification provided for stray voltage testing, as explained below. In other words, the justification was not specific to OH inspections. Under this assumption, the previous cycle was essentially completed in 2005, and the new cycle should start with 2006. The Company, however, appears to be deferring inspections from 2006 and 2007. Con Edison should be inspecting the 287,000 poles over five years and spreading the cost of the inspections over five years. In support of this view, in response to CPB IR 32h, the Company stated that

"In order to proceed with regular scheduled inspections and meet the PSC mandate, the company plans to conduct inspection on 20% of its overhead facilities each year, beginning in the rate year". However, the Company has provided no information to verify its cost estimate and to explain whether its projected cost for the three-year period beginning April 2009, are costs for three years of inspections, or based on five years of inspections.

Q. Did you use historical cost information?

A. No. Despite being requested in CPB IR 2(d), the Company did not provide any historical cost for OH inspections. We asked for five years of costs for the period 2002-2006 along with budgeted amounts for 2007 and 2008, but the response was limited to underground inspection information and data were provided for only three of the five years requested. The requirement and/or mandate for certain inspections and testing to be performed over a five year period signifies the importance of five years of information, yet the Company repeatedly refuses to provide this data.

Q. Are there other concerns with the development of the Company's cost estimate?

A. Yes. The Company purports that the estimate is based on 20% of the poles being inspected each year. Past practice is evidence that the Company does not follow this practice. In addition, the Company acknowledges in its response to CPB IR 32h, that inspections occur during scheduled maintenance on other OH facilities. If the estimate is based on inspecting 20% of all the poles annually, it then ignores the fact that inspections are occurring during regular maintenance, and as a result will duplicate costs recorded elsewhere.

Q. Are you recommending an adjustment to the OH inspection request?

A. Yes. Company workpapers provide no detail as to how the costs were developed for the rate year and absent historical cost information and even budgeted information for 2007, the Company's derivation of its cost estimate cannot be replicated. Con Edison should not be allowed to arbitrarily insert costs in the rate year without supplying adequate information as to how the cost was developed.

We are recommending that the projected rate year cost increase of $5.443 million be reduced by 50% due to the Company's failure to adequately supply information, as requested, that could be utilized to determine the reasonableness of its estimate. A reduction of $2.721 million is recommended.

<u>5-Year Underground Structure Inspection Program</u>

Q. What did you determine from your review of the underground inspection cost request?

A. The Company is requesting $35.001 million in costs in the rate year compared to the indicated $11.1 million of test year costs, or a 215% increase. Company workpapers, in the justification section, cited the requirement that facilities must be reviewed over a five-year period. As noted in our discussion on the OH inspections, our request for five years of historical was not answered. We received only three years of cost information. According to the response to CPB IR 2(d), the Company spent $0 in 2004, $8.5 million in 2005, and $6.8 million in 2006 for underground inspections. The budgeted information requested for 2007 and 2008 was not provided either. According to the Company's workpapers, there are 275,000 inspections required over the five-year period. The response to NYC IR 80, indicated that there were approximately 90,000 inspections completed in 2005 and 2006, 50,000 inspections planned for 2007, and 130,000 will be required to meet the mandated goal. The approximation of 90,000 inspections for 2005 and 2006 correspond with the 89,795 inspections for 2005 and 2006 noted in the workpapers.

Q. Why did you state that the test year cost was indicated to be $11.1 million?

A. The test year expense on Exhibit__ IIP-8 is $11.1 million; however, in response to CPB IR 2(d), the 2006 expense was listed as $6.8 million. The workpapers indicate the 2006 cost is $11.1 million also, but there is concern with this amount since the 2005 cost for 44,728 inspections was $8.5 million and the cost listed for 2006 was $11.1 million for 45,067 inspections. That would equate to an average increase of 30% per inspection between 2005 and 2006.

Q. Are there other concerns with the Company's rate year request?

A. Yes. The Company's response to DPS Staff IR 329.9, indicates that for the rate year, the targeted number of inspections is 75,447. In each of the subsequent two years, the inspection goal is 55,048. The rate year appears to be loaded with more inspections and costs. Assuming that the $11.1 million cost for 2006 was accurate, the average cost would be $246.30 per inspection. The average cost in the 2009 rate year for the 75,447 inspections is projected to be $463.92. The increased cost per inspection has not been justified in the filing. The Company's request is overstated in terms of both the number of inspections and the average cost per inspection.

Q. What adjustment are you recommending?

A. The Company's request for $35.001 million should be reduced $20.813 million to $14.188 million.

Q. How did you determine your adjustment?

A. We determined the average cost for inspections for 2005 and 2006, to be $218.27 and then multiplied that unit cost by 65,000 inspections, obtaining $14.188 million. The 65,000 inspections are one-half of the remaining 130,000 inspections for the last two years of the five-year period, as indicated in the response to NYC IR 80.

Q. Should you have reflected some increase for inflation for the historical average?

A. No. The Company applied an escalator to the historic cost and program changes in its adjustments, so in essence, the Company's use of a projected cost rate along with the escalation would result in a double dip. Only a historical cost is required.

<u>Annual Stray Voltage Program</u>

Q. What are your concerns with the Company's request for $12.522 million for the annual stray voltage program?

A. The Company's Infrastructure Investment Panel testifies at page 116, that in 2004, over one million facilities were tested, 730,000 facilities were tested in 2005, and "These facilities were tested again in 2006". However, according to the response to CPB IR 2, there were no costs in 2004 for the one million facilities tested, the cost for testing 730,000 facilities in 2005 was $14.0 million, and the cost for retesting in 2006 was $6.8 million.

That same response also indicated that the Company budgeted $6.8 million for 2007. If the need was critical, and we are not saying that it isn't, you would expect to see an increase in the 2007 budget. Instead there is an increase to $12.522 million in the year that rates are to be established. According to the response to NYC IR 81, the cost for testing could possibly be reduced if the mobile stray voltage testing can be used to satisfy the testing requirements.

We are also concerned with the inconsistency between the Company's testimony and its workpapers. The workpapers state that there are "approximately 736,000" facilities accessible to the public and "The safety standards include requirements that electric utilities test all of their publicly accessible transmission and distribution facilities for stray voltage and inspect all of their electric facilities once every five years." The Company testimony claims to have performed 100% or more testing of their facilities in each of the years 2004-2006. If the testimony is relatively accurate, then the historical annual cost for 100% testing, or more, is in the range of $6.8 million to approximately $14 million. The most recent historic level of spending is comparable to the 2007 budget of $6.8 million. The response to CPB IR 2, indicated that reported shocks resulting from stray voltage have been on the decline. In response to CPB IR 32a, the Company confirmed the decline. The program is apparently having some success at the current testing rate of 100% per year.

Q. How is it that the Company tested over a million facilities in 2004, but shows no cost associated with that testing?

A. According to the response to CPB IR 32b, because the PSC mandate was not in affect, there were no expenditures related to this program. We question the Company's accounting practices and policies for cost measurement if that is the case. In the many years of analyzing costs in utility proceedings and in the public sector, when companies incur significant costs for certain activities, the cost of that activity is captured in a work order, job order or some responsibility area so that the company can evaluate the cost of a project or undertaking. This would be especially true when a significant project like a full system stray voltage testing is undertaken because of a tragic event such as was the case for Con Edison in 2004.

Q. Why is the cost projected to increase in the rate year?

A. Based on the response to DPS Staff IR 328.1, the increase is driven by the Quality Assurance & Program Oversight costs that exceed $3 million in the rate year. Based on the response to DPS Staff IR 328.2, some cost for oversight existed in the test year, but may have not been included in the test year amount used by the Company to prepare its proposal.

We also note that the Company's responses to questions indicate discrepancies as to the various cost components for the rate year. In response to DPS Staff IR 45, the total cost for the rate year is the same

$12.522 million, but the Quality Assurance & Program Oversight costs are $2.647 million instead of the $3 million plus identified in response to DPS Staff IR 328.1. If the Company cannot keep the projected cost consistent, it is questionable as to the reliability of the cost estimate in total.

Q. Are you recommending an adjustment to the Company's request for $12.522 million?

A. Yes. There is no apparent cost justification for a $5.722 million increase over the test year level of $6.8 million for stray voltage testing, especially taking into consideration the historic spending for the same level of testing and the projected increase in mobile testing that is proposed to complement manual testing. Additionally, there is no justification for the significant added cost for oversight. In addition, since a separate adjustment is made for escalation, there is no apparent need to reflect an increase in the test year cost levels. The Company's projected cost of service should be reduced by the unjustified $5.722 million to the test year expense level of $6.8 million. If, however, the Commission orders the Company to increase the frequency of its stray voltage inspections, a commensurate increase in the rate year expense projection would be warranted.

Mobile Stray Voltage Testing

Q. Do you have any concerns about the Company's proposed Mobile Stray Voltage Testing Program?

A. Yes. As indicated in our discussion on the stray voltage testing, the Company is apparently testing 100% of its facilities each year and the mobile program complements the annual testing with additional testing. As stated earlier, the results of the historical level of testing have shown that a decline in shocks has occurred. With a decline in shocks, it would be anticipated that there would be a decline in cost for repairs and standby charges.

We also note some additional concerns. First, while the test vehicle is to perform the testing at 20 miles per hour, the response to DPS Staff IR 327.2, indicates that in an eight-hour day, only 20 miles is traveled. In addition, in response to DPS Staff IR 327.16, the Company indicates a significant increase in stray voltage detection, especially in 2007, despite the decline in the number of reported shocks noted earlier. Also, according to the response to DPS Staff IR 327.4, an increase in standby costs has been observed along with a significant increase in the cost per detection. In 2006, the standby cost per detection was $306.12 and in 2007 that cost per detection is $1,044.96. While the increase in cost for standby charges has spiked, the increase in vehicle operation expense and electrician support to address the detections have not had similar unexplained spikes. There appears to be some issues with the program that need to be resolved, primarily whether the reported detections are valid and whether the spike in costs for standby charges is justified.

The Company's request for the significant increase of $7.43 million for mobile stray voltage testing does not appear to be cost justified. The response to CPB IR 2(b), indicated that all underground facilities, approximately 273,000, were tested in 2006. There is evidence that additional mobile testing has been performed and has produced favorable results. There is no question that the cost for mobile testing could increase because the Company decided to triple the number of vehicles on hand. In fact, the Company budgeted $9 million in 2007, which would allow for a significant increase in mobile testing. The $10.883 million in the rate year is considered excessive given the level of testing being performed and the assumption that with the number of detections already identified there will be an improvement to the system, reducing the cost for repairs and standby service.

Q. What adjustment are you recommending to the Company's request for $10.883 million?

A. The Company will have an increase in cost if they are to utilize the added vehicles acquired. There may be some question whether the number acquired was necessary. Until there is sufficient justification for the increases in cost above the 2007 budget, we recommend that the test year cost of $3.453 million be increased to $9 million. That would reduce the Company's request for $10.883 million by $1.883 million.

Network Transformer Vault Cleaning Program

Q. Did you review the cost request for the new Network Transformer Vault Cleaning Program?

A. Yes. The Company is requesting $5.488 million for the rate year to fund this cleaning program which would be performed on a five-year cycle. The cost proposal assumes that seven contractor crews at a cost of $2,000 per day per crew, will be required to clean approximately 5,000 vaults a year. In addition to the seven crews, the Company is requesting 10 additional employees to support the crews at an annual cost of $756,000. There is an estimated cost per ton for waste, but according to the response to DPS Staff IR 342, the Company has no way to determine the waste attributable to vault cleaning.

Q. What are your concerns with the Company's request?

A. The Company's workpapers do not show how the $5.488 million estimate was determined, and I have been unable to replicate that estimate. Using Con Edison's projected daily contract labor rates including the Saturday and Sunday rates, the average daily contract labor rate would be $2,100 for a contractor crew. First, there is a concern with the use of a daily crew rate that exceeds $2,000.

Second, the extended cost of $2,100 per day for 245 days for 7 contractor crews equals $3,601,500. The cost for the ten Company employees purportedly required to support the seven crews is $756,000.

That totals $4,357,500. The Company stated it is unable to project the amount of waste that will be removed, so including an estimate of the cost of waste, would be purely speculative. There is also a concern regarding the number of employees required to support the program. The Company has requested a manger, a planner, six supervisors and two clerical staff. This support staff appears excessive.

Finally, the Company indicated, in response to NYC IR 150, that of the nine programs included in the Public Safety and Environmental Program list, this program was the least important.

Q. Are you recommending an adjustment to the Company's request for $5.488 million?

A. Yes. The Company's request for support staff is considered excessive and very possibly premature. That would leave $4.732 million of other costs for this program. However, any adjustment for labor we would make for this program has already been factored into our overall labor adjustment for program changes. We believe the program has merit and could produce some cost savings that the Company has not recognized in the filing. Generally, new programs are phased in and we recommend that approach with this program. We recommend that one-half of the $4.732 million of contractor costs, or $2.366 million, be allowed on the condition that the Company establishes a work order or some method of capturing the cost for future review as evidence of the actual cost for the program. A reduction of $2.366 million to cost of service is recommended for this program.

Q. What is the total adjustment to the Company's request for Public Safety & Environmental cost?

A. The total adjustment for the programs discussed above is a reduction of $33.505 million. The Company's request and our recommendations are shown on Exhibit___(LA), Schedule 5.

Storm Hardening & Response

Q. What increase in cost is being requested for the Storm Hardening and Response program?

A. The Company is requesting that test year expense of $7.944 million be increased by $18.905 million to $26.849 million. The major reasons for this increase are proposed programmatic expansions for danger tree removal, line clearance, the double wood program and maintenance associated with non-network reliability maintenance. The specific program costs of greatest concern will be discussed separately.

Distribution Line Clearance and Danger Tree Removal

Q. What are your concerns with the line clearance request?

A. The Company, on Exhibit__ IIP 8, under the program caption “Storm Hardening and Response,” has reflected a program change adjustment of $7.995 million for distribution line clearance, increasing the test year cost from $5.76 million to $13.755 million. Company workpapers indicate the cost increase is due to an accelerated three-year line clearance cycle. In response to CPB IR 4 (b), the Company clarified that this proposed adjustment was for the distribution program and they provided what was perceived to be historical cost data for three of the five years requested.

According to that response, in 2004 – 2006, the Company spent $6.698 million, $7.284 million and $10.092 million, respectively, for “Electric Operations Distribution line clearance”. The response also indicated that the 2007 budget was $9.5 million. However, the Company’s recommendation is based on the assumption that it spent $5.760 million in 2006 on this program, not the $10.092 million identified in this response. The difference of $4.332 million is significant. We requested further information regarding this issue in CPB IR 34, and the Company responded that the $10.092 million includes costs not reflected in the Company’s Exhibit__ (IIP-8). However, it did not provide a satisfactory explanation of what those costs are, or why they are sometimes included and sometimes excluded from Company information. We are also concerned that the Company indicated a need for increasing its spending on this project, yet the 2007 budget reflects a decline in spending.

We are also concerned about the Company's proposed adjustment of $632,000 for danger tree removal under the program caption "Storm Hardening and Response". The concern is not with the Company's expenditure of funds for this line maintenance, but with the fact that this is being reflected as a new program for distribution maintenance. Danger tree removal is a common practice by electric utilities that apparently has not been practiced by Consolidated Edison. In addition, the Company's estimated cost of removal per tree for danger trees appears overstated. The Company is using an estimate for this new program of $702 per tree. In a current case in Vermont, the average cost for removal over the last five years is $158.16 per tree.

Q. Do you have a recommendation regarding the Company's proposed spending for tree trimming?

A. Yes. It is very common for tree trimming costs included in rates to be based on an historical average. Although there is a preference to utilize a five-year average if an average were to be used, we can only recommend a three-year average because the Company did not provide the five years of expenditures requested. Using the three years of spending provided in response to CPB IR 4, it spent an average of $8.025 million on the program. Based on the fact that this information includes the additional $4.332 million cost not considered in the Company's Exhibit__ (IIP-8) and not adequately explained, the estimate is generous. That would require a reduction of $5.73 million ($13.755 million - $8.025 million) to the Company's request.

Q. Are you recommending an adjustment for the Danger Tree Removal request made by the Company?

A. Yes. The cost per tree is considered excessive compared to neighboring Vermont. Assuming a very generous cost per tree of $325, the cost for the removal of 900 trees would be $292,500. With this estimate, the cost for danger trees should be reduced by $339,500.

Q. Do you have any other recommendations regarding distribution line clearance and danger tree removal?

A. Yes. We also recommend that the Company be required to maintain an annual summary of the costs expended for these programs. If the Company fails to expend $292,500 for danger tree removal and $8.025 million for distribution tree trimming in any year during which the new rates are in affect, then a deferred liability will be set up to ensure that the funds are spent as intended. The liability can be utilized in future years until rates are reset, and if not expended, the funds would be used for the benefit of ratepayers. Similarly, if the Company chooses to expand those projects, it should be permitted to defer the associated costs that are in excess of the amounts reflected in rates.

Double Wood Program

Q. What is the Double Wood Program?

A. The system will require new poles for various reasons from time to time. The pole may be for load relief, due to storm damage, or due to vehicle accidents. The cost for this program is the cost required to transfer equipment from the old pole to the new pole.

Q. What did you determine from your review of the Company's request for $5.235 million in the rate year for this program?

A. The Company's request for $5.235 million represents a 489% increase over the test year cost of $889,000. According to the Company's workpapers, there is an assumption that 2,250 poles will be replaced in the rate year at a cost of $2,300 per pole. In addition, $60,000 is required for two Company supervisors to oversee the contractors. Currently, the Company estimates there are 6,000 double poles that are in the system. As indicated above, the Company plans to eliminate 2,250 in the rate year, and 2,250 and 1,500 in the following two years. Essentially, the Company has a three-year plan to eliminate the 6,000 double poles on the system.

Q. What concerns, if any, do you have with the Company's request or plans?

A. According to the response to CPB IR 5, Con Edison incurred no costs related to this work in 2004, despite the high number of double poles that needed to be eliminated. The response also indicated that in 2006, 200 poles were replaced at a cost of $889,000, or $4,445.00 per pole. Finally, the response stated that "It is planned to complete 930 poles in the rate year at the same unit costs."

There are significant differences in the estimates of the number of poles to be eliminated and the cost per pole, between this response and the information provided in Company workpapers. To further complicate the issue, the response to CPB IR 35, indicated that a 2005 survey identified approximately 6,000 poles on the system, and stated that they were to be removed in the rate years ending March 31, 2009, March 31, 2010 and March 31, 2011. Apparently, the Company is attempting to catch up on work that was limited, or not done at all in previous years, as illustrated by the fact that nothing was spent in 2004 and only 200 poles were eliminated in 2006. It is troubling that a program identified as urgent is not taking place until the rate year in this filing.

We are also concerned that the costs in question should be treated as capital costs. It appears, based on the response to CPB IR 6, that the Company is of the opinion that because the transfer of equipment to the new pole did not take place at the time the new pole was set, the costs are now minor and should be expensed. The purported justification for this is the Company's Property Accounting Manual, for which most of the pages date to March, 1983, and that references Part 168, Paragraph 168.10 of the PSC Uniform System of Accounts. It should be noted that Part 168 was repealed on June 15, 1999.

Q. Do you know why the Company did not address this problem earlier?

A. No. According to the response to CPB IR 5, higher than anticipated storm work required the Company to shift its resources. We are not aware of why the Company did not spend anything in 2004, why they only spent $951,000 in 2005, or why, despite the need for addressing this concern, the Company only budgeted $900,000 in 2007 for the Double Wood Program. As with a number of other programs, the Company has used the rate year to increase its program costs.

Q. Should the projected costs for this program be adjusted?

A. Yes. The projected costs are excessive and a reasonable amount should be capitalized. We are recommending that the entire $5.235 million be removed from the calculation of the Company's revenue requirement.

Q. Have you reflected an adjustment to plant for the costs?

A. No. As was discussed earlier, the differences are significant between the workpapers and the explanations provided in response to CPB IR 5. We are unable to properly estimate the number of poles and the average cost for the poles to be eliminated because of the differences. The Company has failed to support its proposed costs for the Double Wood Program, and therefore, no cost should be allowed.

<u>Maintenance Associated With Capital Work (Non-network Reliability)</u>

Q. What is your concern with the maintenance program for non-network reliability?

A. The Company has requested $6.377 million in the rate year, which is $5.082 million more than the $1.295 million that was expended in the test year. There was no discussion that could be identified in the Company's testimony that explained how the projected costs were determined. The workpapers that were located provided no detail on how the costs were developed. Simply put, there were numbers on a piece of paper and no supporting documentation and/or calculations to establish any justification for the costs. The costs are not considered known and measurable.

Q. Should an adjustment be made for this unknown cost increase?

A. Yes. Although no support exists and the entire amount of the increase should be disallowed, we recognize that the Company will be incurring some added cost associated with the extensive capital program that it is undertaking. Therefore, similar to some of the other unexplained and unjustified increases, we are recommending that the Company's revenue requirement be adjusted to reflect 50% or $2.541 million of this proposed increase.

Q. What is the total adjustment to the Company's request for Storm Hardening & Response cost?

A. As shown on Exhibit___(LA), Schedule 5, page 3 of 3, the total adjustment for the programs discussed above is a reduction of $13.845 million.

FACILITIES EXPENSE

Q. Could you explain the Company's request for an increase in projected facilities expense of $18.692 million?

A. Yes. The Company summarizes this proposal on Exhibit__ (CMB-2). The column labeled "Program Changes 2009", reflects the program changes that are to be added to the cost in the column "Historic year 2006" to obtain the total amount requested for facilities. However, the test year amounts cannot be verified to test year amounts on Company Exhibit ___(AP-5) Schedule 1, so there is no way to verify the accuracy of the test year dollars. To further complicate the derivation of the dollars in the rate year, the program change amounts on Exhibit__ (CMB-2) are total Company amounts, and the only way to trace the costs from that exhibit to the filing schedules is through Schedule 6, which includes totals from Exhibit__ (CMB-2) and the electric operations allocation. As previously explained, the lack of cross references from witness exhibits to schedules in the filing raises concerns as to the validity of the numbers included in the filing. It is also troubling to this panel that this witnesses' exhibits are not assembled uniformly throughout the Company's filing.

Q. Did the workpapers provide the information necessary to evaluate this proposal?

A. No. For example, Exhibit__ (CMB-2) shows a total rate year cost for Flooring Upgrades Programs of $1.572 million and the workpaper with the same program title shows a rate year cost of $810,000. In addition, there is a very limited explanation of why costs are being incurred for Associated O&M Costs – Capital Projects. This program represents the largest increase in the facilities expense category, and includes $12.26 million plus Labor of $.7 million for total of $12.96 million. A second workpaper ostensibly for the $12.26 million amount contains a number of calculations, none of which can readily be reconciled to the $12.26 million figure. Overall, the lack of supporting documentation for the cost estimates makes it impossible to assess the reasonableness of the Company's request.

Q. Are there other concerns with the Company's request?

A. Yes. The expenses are basically single-period costs being incurred as the result of capital projects that will provide improvements to facilities to be used over a period of time. Other costs are for improvements to the property that one would expect to be capital costs. Individually, it could be argued, that the costs are maintenance. However, the fact that the Company is doing a major renovation and breaking the cost into smaller components should not be a means for it to expense, rather than capitalize, these costs. Con Edison's approach on these aspects of facilities expense is similar to the treatment the Company proposes for bird discouragers and the Double Wood Program. Individually the cost may be minor, but in the aggregate the cost is significant when compared to historical spending. It is not appropriate to establish rates with one-time costs. If rates are set that include the costs in question and they are not adjusted after the year is complete, ratepayers will continue to pay costs that the Company is no longer incurring.

Q. What is your recommendation?

A. The $11.86 million of program change cost identified on Exhibit__ (CMB-2) as Associated O&M Costs – Capital Projects, should either be capitalized, or deferred, and written off over an extended period of time. If the Company had better explained these costs, we would be inclined to recommend that they be treated as capital costs. However, as discussed above, there is a lack of sufficient detail supporting the development of the costs. Accordingly, we recommend that the electric portion of the costs, estimated to be $9.623 million (11.86 million x 81.14%), not be included in the Company's revenue requirement. If the Commission believes these costs are reasonable, they should be capitalized.

We also recommend a reduction in the projection of Building Infrastructure Restoration expense. Arguably, that expense could also be capitalized. Historically, the average expense, based on the response to

CPB IR 19(d) and as shown on Exhibit___(LA), Schedule 6, has been $1.072 million a year. The projected increase to $5.36 million is considered excessive. We recommend that the added cost of $4.403 million ($3.573 million for electric operations) be deferred and amortized over five years. The renovation costs do provide a benefit to future periods and appropriately should be charged to those future periods. The adjustment to the rate year net of the first year amortization would be a reduction to electric operation expense of $2.858 million ($3,573,000 - $715,000).

Finally, we recommend the Master Plan Study and Analysis cost estimate of $1.125 million, of which $912,800 will be charged to electric operations, be deferred until the cost is actually known and measurable and it can be established that there was a benefit to ratepayers from the study. The total recommended adjustment to facilities electric operations, as show on Exhibit___(LA), Schedule 6, is a $13.394 million reduction to the rate year program changes of $18.692 million.

CUSTOMER OPERATIONS

Q. Did you review the Company's request for additional costs for Customer operations?

A. Yes. A review was made of the testimony, exhibits and workpapers of the Customer Operations ("CO") Panel, as well as the panel's responses to information requests. After our analysis, we were unable to find sufficient justification for the net $15.902 million of program changes being requested for electric operations. The requested increase consists of $6.610 million for General Education and Outreach (Exhibit__ (CO-3), $8.471 million for Advanced Metering (Exhibit__ (CO-1), $282,600 for Mandatory Hourly Pricing Expansion (Exhibit__ (CO-3), AMR/AMI cost savings of $1.778 million and added labor and other costs of $2.316 million for added customer service representatives.

Q. Would you identify some concerns that you have from your review?

A. Yes. As we indicated earlier, the Company's filing lacks organization, detail and cross referencing sufficient to provide a complete understanding of its rationale for including costs and substantiation of the costs. An example is the Company's response to CPB IR 14g, in which we requested that the Company identify where in the CO Panel's exhibit a $1.3 million increase in labor dollars was reflected. The Company's response did not answer that question. In fact, the responses to CO Panel questions seemed to indicate a total lack of awareness by Company witnesses as to what is included in the filing. For example, a number of the CPB questions requested the Company to identify where the costs were reflected on Company Schedule 8. The responses stated the costs are not reflected on Schedule 8, but they can be found on Schedule 6, page 3. The fact is, the costs on Schedule 6, page 3 are on Company Schedule 8.

Another concern is that our repeated requests for supporting documentation for the increase in costs were not responded to, as illustrated below. It is difficult, if not impossible, to determine the reasonableness of cost increases when the Company does not provide supporting documentation for their estimates. If the cost cannot be supported, then the costs should not be allowed to be recovered in rates.

Q. Could you provide examples of requests for supporting documentation that were not properly responded to?

A. Yes. CPB IR 14o, requested supporting documentation for the Web Based Information Campaigns projected to cost $800,000 as discussed on page 47 of the CO Panel's testimony. The reply stated that the estimate was "based on verbal information provided by service vendors". That response does not sufficiently provide documentation for a cost increase.

CPB IR 14s requested supporting documentation for $2.87 million of costs that represent an $860,000 increase over test year costs. No support was provided in the response. The response simply stated that the Company plans to intensify its effort to reach the Company's diverse customer base.

Q. Are there other concerns with the CO Panel's requested increase in spending?

A. Yes. The Company has requested $2.8 million for two direct mailings of various informational topics. The cost of the informational material is estimated to be $200,000 per mailing for a total of $400,000. The balance of the request is postage. We are concerned with this request because the information could be included with billing as is typically done by most utilities. Second, the information, or very similar information, is readily available on the Company website and/or through other media sources. Finally, in response to CPB IR 14q, a request for supporting information, the Company states that "we mail things separately" suggesting that this is already being done yet the program is identified as a new program. It appears that these projected costs are redundant and excessive. If the program is to be allowed, it should be tested first with a targeted customer base and only once a year.

Another concern is the significant proposed increase in media spending. In the test year, the Company spent $1.465 million and in the rate year they propose to spend $4.265 million. It should be noted that $800,000 of this is the unsupported web based information campaign. The workpapers for the entire General Outreach Program of $10.15 million, of which this $4.265 million of test year costs is included, consists of only one-half a page of a very general description and the projected funding needed. Here again, we are concerned with the undocumented increase in cost that if allowed, it should be on a test basis to a targeted group of customers. The Company's request is excessive, unsupported and should not be allowed.

Q. What adjustment are you recommending for the General Outreach Program?

A. As a general matter, it is important that consumers be provided accurate and timely information to, among other things, help them make informed decisions and advise them of important public policy issues. However, because of the general absence of supporting information, we recommend that the Company's general education and outreach request for $10.15 million be reduced by $4.46 million. This is comprised of the unsupported increases of $860,000 for the Community Outreach – Events/Sponsorships, Education and Awareness and the Web Site Improvements programs; $1.8 million of the $2.8 million requested for the Direct Mail program; the unsupported $800,000 for web based information campaigns and $1 million of the additional $1.95 million requested for the various media programs. This reduction still allows for an increase in General Education and Outreach of $2.15 million or 60.7% over the test year spending of $3.54 million.

Q. Please summarize your recommendation regarding the Company's Advanced Metering Infrastructure ("AMI") request.

A. The Company has proposed to implement AMI throughout its service territory, following completion of three pilot projects. As explained in the testimony of CPB witness Dr. Elfner, this proposal should not be adopted at this time. Accordingly, the CPB recommends that all projected capital and O&M expense associated with the AMI proposal be removed from the revenue requirement projections used to establish rates in this proceeding. The Company should be permitted to recover the costs of the pilot programs. However, since those costs are apparently one-time in nature, they should not be embedded in revenue requirement established in a one-year rate case.

If however, the Commission does not adopt this recommendation, it should adjust the Company's projection of O&M expense associated with the AMI project.

Q. Please explain your concerns with the projected increase in O&M costs associated with the AMI initiative.

A. The electric operations capital requirements for this program are projected to be $59 million in 2008, $106.6 million in 2009, and $119.9 million in 2010 for a total cost for electric operations of $285.5 million. Prorating the 2009 costs, it is estimated that $85.65 million will be expended by March 31, 2009, the end of the rate year. The initial capital expenditures for this project, as of the end of the rate year, represent only 30% of the total projected AMI project costs, yet the total Company's O&M

request includes a disproportionate increase in the rate year. In particular, of the total projected increase in O&M for this program of $10.668 million, the Company projects that $10.331 million (96.8%) will occur in the rate year even though 70% of the project is not yet completed.

In addition to this mismatch, the bulk of any projected cost savings associated with the AMI project are not expected to occur until 2010 and 2011. The mismatch of costs and costs savings is a major concern. In response to CPB IR 40(c), the Company asserts that labor expense reductions will not occur as a result of this project for several years, since communication equipment must be installed and tested before any meter installations are made. We question how the communication system can test the meters if they have not yet been installed. The Company's attempt to justify the inclusion of the costs in the rate year without reflecting cost savings, is questionable.

Q. Are you recommending an adjustment be made to the Company's O&M request for the AMI project?

A. Yes. As stated earlier we recommend that the entire O&M amount be removed from the Company's request, however we have reflected in our recommended adjustments our alternative recommendation. Since only 30% of the capital costs are expected to be spent in the rate year, it is reasonable to assume that 30% of the system will be operational and therefore, only 30% of the projected additional O&M costs should be required. This may be an overly optimistic expectation because generally until the project is complete, capital costs are incurred before the system can be considered to be in service (i.e., construction in progress). Further, this assumes that the project will be on schedule.

On the assumption that 30% of the costs are reasonable, the rate year request would be reduced to $3.2 million ($10.668 million x 30%) on a total Company basis. The adjustment to electric operations would be a reduction of $5.93 million to the Company's request of $8.471 million, for a rate year expense of $2.541 million ($8.471 million x 30%).

Q. What is your total adjustment to the Company's request for Customer Operations cost?

A. The total adjustment for the programs discussed above is a reduction of $10.39 million in rate year expense.

<u>STEAM OPERATIONS</u>

Q. Did you review the Electric Production Panel's testimony and exhibits?

A. Yes. The Electric Production Panel has requested a net increase of $7.162 million for steam operations. This is comprised of the following major cost increases: $1.173 million for preventive maintenance, $403,000 for water, $350,000 for boiler cleaning, $2.244 million for gas turbine inspections and repairs and $3.2 million for facility maintenance and stack painting.

Q. Do you have any concerns with the Company's request?

A. Yes. The Company has not sufficiently justified the proposed increase. In particular, it did not provide requested support in response to information requests.

Q. What problems did you find with the Company's responses?

A. As with all our requests for five years of historical information, the Company failed to supply 2002 and 2003 historical cost data. CPB IR 13b requested support for the statements referred to on page 18 of the Electric Production Panel's testimony and the Company's response was "this information is available on the City's website." That is not a sufficient response. The City's website is quite extensive and changes over time. If the Company is unable to provide a copy of the statements it relied upon in making its recommendations, it has not provided the information necessary to support its proposal, or to facilitate evaluation by the CPB, other parties or the Commission.

Another problem was that CPB IR 13f requested a schedule of inspections performed on electric production plant facilities and the maintenance that was completed as a result of those inspections over the period 1997-2006. Nothing was provided in the response. This question was asked because the Company testified that inspections occur every five years. Therefore, it was necessary to obtain the results of the inspections and determine whether and when the maintenance identified was actually performed. In an attempt to acquire the information, we asked the Company again for inspections performed from 1997-2006 in CPB IR 38. The response objected to the time frame requested but did provide the information.

In the ten-year span, 36 inspections resulted in 23 projects requiring maintenance. Of the 23 projects, 11 have been completed, seven are in progress and five are still in the planning stage. The projects that are still in progress were initiated by inspections that occurred between November 2000 and February 2007. Projects that are in the planning stage resulted from inspections between May 2004 and December 2006. Based on this review, the inspections appear to be done annually and the maintenance, if required, is in fact, completed over a period of time. As a result, there is no substantiation that the maintenance the Company proposes to conduct as a result of inspections, will be performed in the rate year. Once again, the Company has failed to adequately support its request.

Q. Do you have any other concerns regarding the Company's response?

A. Yes. It is also a concern when the response to a data request seeking a comparison of historical and budgeted information, reflects different test year cost levels than what is reflected in the filing. Of seven different categories of costs listed in the attachment to the response to CPB IR 13, five reflected a cost different than that shown on Company Exhibit__

(EPP-2) for the test year. As noted in the distribution line clearance discussion above, the Company provided different amounts than what was reflected in the filing. The differences raise some concern regarding the reliability of the information supplied in the filing or in response to data requests.

Q. Are you recommending an adjustment to the requested increase in expense for steam operations by the Electric Production Panel?

A. Yes. The facilities maintenance increase of $3.2 million is considered excessive. The response to CPB IR 13 indicated that over the years 2004-2006 the average amount expended was $2.976 million and the Company only budgeted $1.487 million in 2007 for the costs it now identifies as necessary in the rate year. As shown on Exhibit___(LA), Schedule 7, we recommend that rates reflect average spending in the 2004 – 2006 period. Historical spending levels and the Company's practice of performing maintenance over time in response to inspections, justifies our proposed $1.272 million reduction to the rate year request of $4.248 million. We note that our adjustment to $2.976 million ($4.248 - $1.272) for the rate year is conservative, in view of the Company's 2007 budget of $1.487 for facilities maintenance, that is less than half of historical average expenditures.

We also recommend that the combined preventive and corrective maintenance request of $6.284 million be reduced $2.384 million, to the three-year average expense of $3.9 million calculated from CPB IR 13. The 2007 budget for preventive maintenance, as shown in the response to CPB IR 13 and on Exhibit___(LA), Schedule 7, is $2.421 million. The projected increase in spending above the three-year average and the 2007 budget raises a concern that maintenance was either deferred in anticipation of a rate case or to minimize expenditures despite a need for maintenance. The increase is not sufficiently supported by the filing or based on historical spending.

Finally, the increase of $2.244 million for gas turbine (“GT”) maintenance should be removed from projected O&M expense. A review of the Electric Production Panel’s capital request does not identify any capital costs associated with this particular program. Historically, the Company has spent on average $431,000 a year on GT maintenance, and the largest amount spent was $726,000 in the test year. The explanation provided in the Company workpapers for the proposed $2.244 million increase is that maintenance is required to bring deteriorated GT equipment into operation. The justification and description suggests the costs are more capital in nature than expense. If the costs are allowed at all, they should be capitalized.

Overall, the Electric Production Panel’s request for Steam Operations should be reduced a total of $5.9 million.

INTERFERENCE COSTS

Q. What is the Company requesting for Interference O&M costs in the rate year?

A. The Company is requesting that test year expense of $53.975 million be increased by $52.458 million for a total request of $106.433 million, an increase of more than 97%.

Q. How was the Company's estimate determined?

A. The Company's estimate for interference costs, excluding Lower Manhattan, is based on a formula and New York City's Commitment Plan for capital expenditures. The City's Commitment is uncharacteristically high in comparison to historical levels. The request of $106.433 million for the rate year is significantly higher than the five year average cost of $60.325 million.

Q. What are your concerns with this estimate?

A. The amounts are based on an estimate of costs by New York City and assume that the City will complete a far larger number of projects than it has historically. Additionally, the Company was requested in CPB IR 17(g), to provide supporting detail for the Lower Manhattan interference projects and/or calculations for the amounts shown on the exhibit. The response simply stated "As stated in Mr. Gencarelli's testimony the O&M and capital forecast for the Lower Manhattan projects are developed by preparing order of magnitude estimates for each project based on the past experience of similar projects in the lower Manhattan area". The estimates and any supporting backup were not provided.

Q. Were the workpapers of any help?

A. No. Company workpapers have some broad explanations and some total cost estimates with absolutely no detail showing how the costs were derived. A request for source documents was responded to by referring us to New York City's web site. In our view, that is not adequate support for a request seeking an increase of this magnitude.

Q. Should an adjustment be made to the Company's request for interference costs?

A. Yes. The projected increase in this cost is significant. From 2002-2005, the actual costs averaged about 3% more than budgeted costs for Interference projects. In 2006, the amount budgeted was approximately 14% higher than 2005 and approximately 22% higher than the average for 2002-2005. Yet actual costs for 2006 were only 74.2% of the amount budgeted. The increased budget for 2006 resulted in a significant shift from the historical budget to actual variance. Accordingly, we recommend that the Interference cost request be adjusted based on a comparison of 2006 actual-to-budget data. The $106.433 million projection should be reduced $27.46 million to $78.973 million using the

74.2% actual-to-budget ratio for 2006. We note that our proposed adjustment may be conservative, since the 2006 ratio of actual to budgeted interference spending may not be achievable with the huge increase in interference projected in the Company's filing.

STORM COSTS

Q. What costs are reflected in the rate year for storms?

A. The Company is requesting that $8 million be included in rates. That $8 million is $16.27 million less than what was incurred in the test year.

Q. Is the Company's request reasonable?

A. The Company's request is not a known and measurable amount. According to the Accounting Panel's testimony at page 31, the projection is based on the average cost of storms over fifteen years. However, the response to CPB IR 33(b) states that "the pre-filed testimony should have stated that the Company used 15 years of historical storm activity and projected the cost based on current costs for similar events times the average number of storms we incurred annually". How the Company arrived at its estimate is not known because the testimony was not accurate and the initial response did not state specifically that the testimony was incorrect.

Q. What has been your experience with estimating storm costs for ratemaking?

A. Typically, if an adjustment to the test year is made, the adjustment will be based on an historical average. Sometimes that average will reflect an adjustment to remove the effect of unusual or extraordinary storms. This adjustment is intended to obtain an average that is based on the normal level of storm costs incurred over a period of time.

Q. Using historical costs, could you determine whether the Company's projected cost is reasonable?

A. The Company was requested to provide five years of historical costs but as with other requests, only three years of data were provided. The costs were $.7 million in 2004, $1.5 million in 2005, and $24.2 million in 2006 based on the response to CPB IR 3(a). The 2006 year was definitely not a normal year. In follow-up, the Company was asked to provide the years where storm costs exceeded $5 million. The response to CPB IR 33(a) indicated that in addition to 2006, the 1996 expense was $7.3 million, and the 1997 expense was $9.2 million. In 15 years, the Company had only three years where the cost for storms exceeded $5 million. If the other ten years of storm costs were ignored, the average of the five years for which data have been provided, including the only three over $5 million, would be $8.6 million. In our opinion, the Company's request for $8.0 million is excessive and comparable to a worst case scenario.

Q. What is your recommendation for rate year storm costs?

A. The Company's request should be reduced $3 million from $8 million to $5 million. The Company should be required to maintain a tracking account for storm costs and any deviation between actual costs and the amount allowed in rates should be deferred to prevent any over or under recovery of costs. In future rate proceedings, the amount that is reflected in rates should be based on a historical average of normal major storm costs, of at least five years in length. Large storms or multiple storms resulting in an unusually high level of cost in a single year, would be adjusted before being included in the average calculation.

<u>ESCALATION</u>

Q. Are you taking exception to the escalation applied by the Company in projecting its rate year costs?

A. Yes. Some costs should be escalated to reflect projected inflation. However, some projected costs should not be escalated. In addition, some costs may be subject to inflation, but because the costs fluctuate from year-to-year, the application of an escalation factor is not appropriate.

Q. What costs should not be escalated?

A. Interference costs are based on projections, and escalating those projections would effectively double-count inflation. Our Interference adjustment already removed 25.8% of the $4.776 million of the projected escalation for interference, or $1.232 million. The remaining $3.544 million should also be excluded from cost of service.

Next, we question the appropriateness of escalation on injuries and damages expense. That expense is not tied to inflation like materials and supplies. No justification exists for escalating that projected expense. A reduction of $1.8 million to the Company's projection should be made.

Finally, in the "Other" category, the $47.603 million of costs for program changes that were based on estimated costs in the rate year, increased the normalized test year amount from $90.572 million to $138.175 million. Again, the test year cost may be subject to escalation, but the projected cost already include escalation, so applying the escalation factor to the program changes is a double dip. Therefore, the escalation for "Other" should be reduced $2.237 million ($47.603 x 4.7%). That would result in a total reduction for escalation of $7.581 million.

Q. Should escalation on other expense categories be adjusted to exclude the program change escalation?

A. That is something that could be considered. We focused primarily on the larger and more obvious expense categories that we believe should not be escalated or should be limited specifically to the test year amounts.

PLANT IN SERVICE – PLANT RETIREMENTS

Q. Have you reviewed the projected retirements to plant in service included by the Company in its filing?

A. Yes, we have reviewed the projected retirements to plant in service, focusing on the level of retirements projected to occur from the end of the historic test year, December 31, 2006, through the end of the rate year, March 31, 2009. Based on our analysis, we are recommending an adjustment to the level of projected plant retirements. CPB witness Dr. Elfner will be addressing the Company's proposed capital expenditures and projected additions to plant in service.

Q. Beyond the concerns with the Company's projected capital expenditure levels presented in Dr. Elfner's testimony, do you have any additional concerns with the Company's projected net additions to plant in service?

A. Yes. Based on the review of the Company's workpapers, it appears that its projected retirements to plant in service for the period subsequent to the historic test year through the end of the rate year, are substantially understated. In response to CPB IR 26(a), the Company provided its additions and retirements for the period 2003 through 2006. On Exhibit___(LA), Schedule 8, we have provided the annual additions and retirements to electric plant in service by year for the period 2004 through 2006, and from each of these amounts calculated the average percentage of retirements to plant additions for each of those years. For the 2005 period, we also made an adjustment to remove retirements made by the Company to steam production plant in that year as that is not likely to be a recurring event.

As shown on the schedule, the adjusted average percentage of retirements to plant in service for the period 2004 through 2006, was 13.19%. Based on the Company's workpapers, it has included projected retirements to plant in service for 2007 of $73,880,000 which is 6.5% of the projected additions of $1,141,304,000 for that same period. For 2008, the Company has projected retirements to plant in service of $73,711,000, which is 4.2% of the projected 2008 additions to electric plant in service. Considering the amount of capital expenditures included in the filing for replacement type work and upgrades, it is clear that the projected retirements to plant in service included in the filing are understated.

Q. In what way does the understatement of projected retirements to plant in service impact the revenue requirement calculations in the filing?

A. Typically there is a dollar for dollar impact on plant in service and accumulated depreciation when one reflects retirements. For every dollar retired, typically you have dollar also removed from the accumulated depreciation balance. Thus, the Company's understatement of plant retirements may not impact rate base; however, it does impact the depreciation expense calculations as depreciation rates are applied to the average test year plant balances. Thus, depreciation expense would be overstated.

Q. Are you recommending an adjustment to increase the plant retirements made by the Company in the filing?

A. Yes, however, we have not quantified the adjustment at this time. We recommend that once the Commission determines the appropriate level of additions to plant in service from the end of the historic test year through the first rate year, it then apply the average ratio of plant retirements to plant additions calculated on Exhibit__(LA), Schedule 8, of 13.19%. This amount can then be compared to the $73,880,000 of retirement included by the company for 2007, the $73,711,000 of retirement reflected for 2008. While the additional level of retirements will not impact rate base, it will result in a reduction to the depreciation expense included in the filing.

Q. Does this complete your prefiled testimony?

A. Yes, it does.

ATTACHMENTS

ATTACHMENT I

Mr. Schultz received a Bachelor of Science in Accounting from Ferris State College in 1975. He maintains extensive continuing professional education in accounting, auditing, and taxation. Mr. Schultz is a member of the Michigan Association of Certified Public Accountants

Mr. Schultz was employed with the firm of Larkin, Chapski & Co., C.P.A.s, as a Junior Accountant, in 1975. He was promoted to Senior Accountant in 1976. As such, he assisted in the supervision and performance of audits and accounting duties of various types of businesses. He has assisted in the implementation and revision of accounting systems for various businesses, including manufacturing, service and sales companies, credit unions and railroads.

In 1978, Mr. Schultz became the audit manager for Larkin, Chapski & Co. His duties included supervision of all audit work done by the firm. Mr. Schultz also represents clients before various state and IRS auditors. He has advised clients on the sale of their businesses and has analyzed the profitability of product lines and made recommendations based upon his analysis. Mr. Schultz has supervised the audit procedures performed in connection with a wide variety of inventories, including railroads, a publications distributor and warehouser for Ford and GM, and various retail establishments.

Mr. Schultz has performed work in the field of utility regulation on behalf of public service commission staffs, state attorney generals and consumer groups concerning regulatory matters before regulatory agencies in Alaska, Arizona, California, Connecticut, Delaware, Florida, Georgia, Kentucky, Kansas, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Dakota, Ohio, Pennsylvania, Rhode Island, Texas, Utah, Vermont and Virginia. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on numerous occasions.

<u>Partial list of utility cases participated in</u>:

U-5331	Consumers Power Co. Michigan Public Service Commission
Docket No. 770491-TP	Winter Park Telephone Co. Florida Public Service Commission

Case Nos. U-5125 and U-5125(R)	Michigan Bell Telephone Co. Michigan Public Service Commission
Case No. 77-554-EL-AIR	Ohio Edison Company Public Utility Commission of Ohio
Case No. 79-231-EL-FAC	Cleveland Electric Illuminating Public Utility Commission of Ohio
Case No. U-6794	Michigan Consolidated Gas Refunds Michigan Public Service Commission
Docket No. 820294-TP	Southern Bell Telephone and Telegraph Co. Florida Public Service Commission
Case No. 8738	Columbia Gas of Kentucky, Inc. Kentucky Public Service Commission
82-165-EL-EFC	Toledo Edison Company Public Utility Commission of Ohio
Case No. 82-168-EL-EFC	Cleveland Electric Illuminating Company, Public Utility Commission of Ohio
Case No. U-6794	Michigan Consolidated Gas Company Phase II, Michigan Public Service Commission
Docket No. 830012-EU	Tampa Electric Company, Florida Public Service Commission
Case No. ER-83-206	Arkansas Power & Light Company, Missouri Public Service Commission
Case No. U-4758	The Detroit Edison Company - (Refunds), Michigan Public Service Commission
Case No. 8836	Kentucky American Water Company, Kentucky Public Service Commission
Case No. 8839	Western Kentucky Gas Company, Kentucky Public Service Commission
Case No. U-7650	Consumers Power Company - Partial and

	Immediate Michigan Public Service Commission
Case No. U-7650	Consumers Power Company - Final Michigan Public Service Commission
U-4620	Mississippi Power & Light Company Mississippi Public Service Commission
Docket No. R-850021	Duquesne Light Company Pennsylvania Public Utility Commission
Docket No. R-860378	Duquesne Light Company Pennsylvania Public Utility Commission
Docket No. 87-01-03	Connecticut Natural Gas State of Connecticut Department of Public Utility Control
Docket No. 87-01-02	Southern New England Telephone State of Connecticut Department of Public Utility Control
Docket No. 3673-U	Georgia Power Company Georgia Public Service Commission
Docket No. U-8747	Anchorage Water and Wastewater Utility Alaska Public Utilities Commission
Docket No. 8363	El Paso Electric Company The Public Utility Commission of Texas
Docket No. 881167-EI	Gulf Power Company Florida Public Service Commission
Docket No. R-891364	Philadelphia Electric Company Pennsylvania Office of the Consumer Advocate

Docket No. 89-08-11	The United Illuminating Company The Office of Consumer Counsel and the Attorney General of the State of Connecticut
Docket No. 9165	El Paso Electric Company The Public Utility Commission of Texas
Case No. U-9372	Consumers Power Company Before the Michigan Public Service Commission
Docket No. 891345-EI	Gulf Power Company Florida Public Service Commission
ER89110912J	Jersey Central Power & Light Company Board of Public Utilities Commissioners
Docket No. 890509-WU	Florida Cities Water Company, Golden Gate Division Florida Public Service Commission
Case No. 90-041	Union Light, Heat and Power Company Kentucky Public Service Commission
Docket No. R-901595	Equitable Gas Company Pennsylvania Consumer Counsel
Docket No. 5428	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 90-10	Artesian Water Company Delaware Public Service Commission
Docket No. 900329-WS	Southern States Utilities, Inc. Florida Public Service Commission
Case No. PUE900034	Commonwealth Gas Services, Inc. Virginia Public Service Commission
Docket No. 90-1037* (DEAA Phase)	Nevada Power Company - Fuel Public Service Commission of Nevada

Docket No. 5491**	Central Vermont Public Service Corporation Vermont Department of Public Service
Docket No. U-1551-89-102	Southwest Gas Corporation - Fuel Before the Arizona Corporation Commission
	Southwest Gas Corporation - Audit of Gas Procurement Practices and Purchased Gas Costs
Docket No. U-1551-90-322	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. 176-717-U	United Cities Gas Company Kansas Corporation Commission
Docket No. 5532	Green Mountain Power Corporation Vermont Department of Public Service
Docket No. 910890-EI	Florida Power Corporation Florida Public Service Commission
Docket No. 920324-EI	Tampa Electric Company Florida Public Service Commission
Docket No. 92-06-05	United Illuminating Company The Office of Consumer Counsel and the Attorney General of the State of Connecticut
Docket No. C-913540	Philadelphia Electric Co. Before the Pennsylvania Public Utility Commission
Docket No. 92-47	The Diamond State Telephone Company Before the Public Service Commission of the State of Delaware
Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control

Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation (Supplemental) State of Connecticut Department of Public Utility Control
Docket No. 93-08-06	SNET America, Inc. State of Connecticut Department of Public Utility Control
Docket No. 93-057-01**	Mountain Fuel Supply Company Before the Public Service Commission of Utah
Docket No. 94-105-EL-EFC	Dayton Power & Light Company Before the Public Utilities Commission of Ohio
Case No. 399-94-297**	Montana-Dakota Utilities Before the North Dakota Public Service Commission
Docket No. G008/C-91-942	Minnegasco Minnesota Department of Public Service
Docket No. R-00932670	Pennsylvania American Water Company Before the Pennsylvania Public Utility Commission
Docket No. 12700	El Paso Electric Company Public Utility Commission of Texas
Case No. 94-E-0334	Consolidated Edison Company Before the New York Department of Public Service
Docket No. 2216	Narragansett Bay Commission

	On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission
Docket No. 2216	Narragansett Bay Commission - Surrebuttal On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission
Case No. PU-314-94-688	U.S. West Application for Transfer of Local Exchanges Before the North Dakota Public Service Commission
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 95-03-01	Southern New England Telephone Company State of Connecticut Department of Public Utility Control
Docket No. U-1933-95-317	Tucson Electric Power Before the Arizona Corporation Commission
Docket No. 5863*	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 96-01-26**	Bridgeport Hydraulic Company State of Connecticut Department of Public Utility Control
Docket Nos. 5841/ 5859	Citizens Utilities Company Before Vermont Public Service Board
Docket No. 5983	Green Mountain Power Corporation Before Vermont Public Service Board

Case No. PUE960296**	Virginia Electric and Power Company Before the Commonwealth of Virginia State Corporation Commission
Docket No. 97-12-21	Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 97-035-01	PacifiCorp, dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. G-03493A-98-0705*	Black Mountain Gas Division of Northern States Power Company, Page Operations Before the Arizona Corporation Commission
Docket No. 98-10-07	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 99-01-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-04-18	Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 99-09-03	Connecticut Natural Gas Corporation State of Connecticut Department of Public Utility Control
Docket No. 980007-0013-003	Intercoastal Utilities, Inc. St. John County - Florida
Docket No. 99-035-10	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 6332 **	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board

Docket No. G-01551A-00-0309	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. 6460**	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 01-035-01*	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 01-05-19 Phase I	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket No. 010949-EI	Gulf Power Company Before the Florida Office of the Public Counsel
Docket No. 2001-0007-0023	Intercoastal Utilities, Inc. St. Johns County - Florida
Docket No. 6596	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket Nos. R. 01-09-001 I. 01-09-002	Verizon California Incorporated Before the California Public Utilities Commission
Docket No. 99-02-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-04	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. 5841/5859	Citizens Utilities Company Before the Vermont Public Service Board
Docket No. 6120/6460	Central Vermont Public Service Corporation Before the Vermont Public Service Board

Docket No. 020384-GU	Tampa Electric Company d/b/a/ Peoples Gas System Before the Florida Public Service Commission
Docket No. 03-07-02	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 6914	Shoreham Telephone Company Before the Vermont Public Service Board

Docket No. 04-06-01	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket Nos. 6946/6988	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 04-035-42**	PacifiCorp dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. 050045-EI**	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 050078-EI**	Progress Energy Florida, Inc. Before the Florida Public Service Commission
Docket No. 05-03-17	The Southern Connecticut Gas Company State of Connecticut Department of Public Utility Control
Docket No. 05-06-04	United Illuminating Company State of Connecticut Department of Public Utility Control
Docket No. A.05-08-021	San Gabriel Valley Water Company, Fontana Water Division Before the California Public Utilities Commission
Docket NO. 7120 **	Vermont Electric Cooperative Before the Vermont Public Service Board
Docket No. 7191 **	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 06-035-21 **	PacifiCorp

Before the Public Service Commission of Utah

Docket No. 7160	Vermont Gas Systems Before the Vermont Public Service Board
Docket No. 6850/6853 **	Vermont Electric Cooperative/Citizens Before the Vermont Public Service Board
Docket No. 06-03-04** Phase 1	Connecticut Natural Gas Corporation Connecticut Department of Public Utility Control
Application 06-05-025	Request for Order Authorizing the Sale by Thames GmbH of up to 100% of the Common Stock of American Water Works Company, Inc., Resulting in Change of Control of California-American Water Company Before the California Public Utilities Commission
Docket No. 06-12-02PH01**	Yankee Gas Company State of Connecticut Department of Public Utility Control
Case 06-G-1332**	Consolidated Edison Company of New York, Inc. Before the NYS Consumer Protection Board

* Certain issues stipulated, portion of testimony withdrawn.
** Case settled.

ATTACHMENT II

QUALIFICATIONS OF DONNA DERONNE, C.P.A.

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant and regulatory consultant in the firm of Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I graduated with honors from Oakland University in Rochester, Michigan in 1991. I have been employed by the firm of Larkin & Associates, PLLC, since 1991.

As a certified public accountant and regulatory consultant with Larkin & Associates, PLLC, my duties have included the analysis of utility rate cases and regulatory issues, researching accounting and regulatory developments, preparation of computer models and spreadsheets, the preparation of testimony and schedules and testifying in regulatory proceedings. I have also developed and conducted five training programs on behalf of the Department of Defense - Navy Rate Intervention Office on measuring the financial capabilities of firms bidding on Navy assets and one training program on calculating the revenue requirement for municipal owned water and wastewater utilities. A partial listing of cases which I have participated in are included below:

Performed Analytical Work in the Following Cases:

Docket No. 92-06-05	The United Illuminating Company State of Connecticut, Department of Public Utility Control
Docket No. R-00922428	The Pennsylvania American Water Company Pennsylvania Public Utility Commission
Cause No. 39498	PSI Energy, Inc. Before the State of Indiana - Indiana Utility Regulatory Commission
Docket No. 6720-TI-102	Wisconsin Bell, Inc. Wisconsin Citizens' Utility Board
Docket No. 90-1069 (Remand)	Commonwealth Edison, Inc. Before the Illinois Commerce Commission

Docket Nos. 920733-WS Labelle & 920734-WS	General Development Utilities, Inc. - Port and Silver Springs Shores Divisions. Before the Florida Public Service Commission
Case No. PUE910047	Virginia Electric and Power Company (State Corporation Commission)
Docket No. U-1565-91-134	Sun City Water Company Residential Utility Consumer Office
Docket No. 930405-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. UE-92-1262	Puget Sound Power & Light Company Before the Washington Utilities & Transportation Commission
Docket No. R-932667	Pennsylvania Gas & Water Company Before the Pennsylvania Public Utility Commission
Docket No. 7700	Hawaiian Electric Company, Inc. Before the Public Utilities Commission of the State of Hawaii
Docket No. R-00932670	Pennsylvania American Water Company Pennsylvania Public Utility Commission
Case No. 78-T119-0013-94	Guam Power Authority vs. U.S. Navy Public Works Center, Guam - Assisting the Department of Defense in the investigation of a billing dispute.
Case No. 90-256	South Central Bell Telephone Company Before the Kentucky Public Service Commission
Case No. 94-355	Cincinnati Bell Telephone Company Before the Kentucky Public Service Commission
Docket No. 7766	Hawaiian Electric Company, Inc. Before the Public Utilities Commission of the State of Hawaii
Docket No. 2216	Narragansett Bay Commission

	On Behalf of the Division of Public Utilities and Carriers, Before the Rhode Island Public Utilities Commission
Docket No. 94-0097	Citizens Utilities Company, Kauai Electric Division Before the Public Utilities Commission of the State of Hawaii
Docket No. 5863*	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. E-1032-95-433	Citizens Utilities Company - Arizona Electric Division Before the Arizona Corporation Commission
Docket No. R-00973947 Commission	United Water Pennsylvania Before the Pennsylvania Public Utilities
Docket No. 95-0051	Hawaiian Storm Damage Reserve Case Before the Public Utilities Commission of the State of Hawaii
Application Nos. 96-08-070, 96-08-071, 96-08-072	Pacific Gas & Electric Company, Southern California Edison Company & San Diego Gas & Electric Co.; Phases I & II; Before the California Public Utilities Commission
Docket No. E-1072-97-067	Southwestern Telephone Company Before the Arizona Corporation Commission
Docket No. 920260-TL Counsel	BellSouth Telecommunications Inc. - Florida On Behalf of the Florida Office of Public
Docket No. R-00973953 Commission	PECO Energy Company Before the Pennsylvania Public Utilities
Docket No. 5983	Green Mountain Power Corporation Before the Vermont Public Service Board
Case No. PUE-9602096	Virginia Electric and Power Company

	Before the Commonwealth of Virginia State Corporation Commission
Docket No. 97-035-01	PacifiCorp, dba Utah Power & Light Company Before the Public Service Commission of Utah
Docket No. G-34930705	Black Mountain Gas Division - Northern States Power Before the Arizona Corporation Commission
Docket No. T-01051B-99-105*	US West/Qwest Corporation Before the Arizona Corporation Commission
Docket No. 98-10-019	Verizon Audit Report on Behalf of California Office of Ratepayers Advocates
Docket No. 991437-WU*	Wedgefield Utilities, Inc. Before the Florida Public Service Commission
Docket No. 99-057-20*	Questar Gas Company Before the Utah Public Service Commission
Docket No. 6596	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Docket No. ER02080614	Rockland Electric Company Before the New Jersey Board of Public Service
Docket No. 5841/5859	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board
Formal Case No. 1016	Washington Gas Light Company Before the Public Service Commission of the District of Columbia
Application No. 02-12-028 Commission	San Diego Gas & Electric Company Before the California Public Utilities
Docket No. 03-2035-02**	PacifiCorp - Utah Operations Before the Public Service Commission of Utah
Docket No. 2004-0007-	Intercoastal Utilities, Inc.

0011-0001 Before the St. Johns County Water & Sewer Authority

Submitted Testimony in the Following Cases

Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Case No. 94-0035-E-42T	Monongahela Power Company Before the Public Service Commission of West Virginia
Case No. 94-0027-E-42T	Potomac Edison Company Before the Public Service Commission of West Virginia
Case No. 95-0003-G-42T*	Hope Gas, Inc. Before the West Virginia Public Service Commission
Case No. 95-0011-G-42T*	Mountaineer Gas Company Before the West Virginia Public Service Commission
Docket No. 950495-WS	Southern States Utilities Before the Florida Public Service Commission
Docket No. 960451-WS	United Water Florida Before the Florida Public Service Commission
Docket No. 5859	Citizens Utilities Company - Vermont Electric Division Before the Vermont Public Service Board

Docket No. 97-12-21	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 98-01-02	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 98-07-006	San Diego Gas and Electric Company Public Utilities Commission of the State of California
Docket No. 99-04-18 Phase I	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 99-04-18 Phase II	Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 99-09-03 Phase I	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 99-09-03 Phase II	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 99-035-10	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 00-12-01	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 6460*	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 01-035-01*	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. G-01551A-00-0309	Southwest Gas Corporation Arizona Corporation Commission

Docket No. 01-05-19	Yankee Gas Services Company State of Connecticut Department of Public Utility Control
Docket No. 01-035-23 Interim (Oral testimony)	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 01-035-23**	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 010503-WU	Aloha Utilities, Inc. - Seven Springs Water Division Before the Florida Public Service Commission
Docket No. 000824-EI*	Florida Power Corporation Before the Florida Public Service Commission
Docket No. 001148-EI**	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 01-10-10	United Illuminating Company Connecticut Department of Public Utility Control
Docket No. 02-057-02*	Questar Gas Company Public Service Commission of Utah
Docket No. 020384-GU*	Tampa Electric Company d/b/a Peoples Gas System Before the Florida Public Service Commission
Docket No. 020010-WS	The Woodlands of Lake Placid, L.P. Before the Florida Public Service Commission
Docket No. 020071-WS	Utilities, Inc. of Florida Before the Florida Public Service Commission
Docket No. 03-07-02	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket No. 030438-EI*	Florida Public Utilities Company Before the Florida Public Service Commission
Docket No. 03-11-20	Southern Connecticut Gas Company

	State of Connecticut, Department of Public Utility Control
Docket No. 030102-WS	The Woodlands of Lake Placid, L.P. Before the Florida Public Service Commission
Docket No. 04-06-01*	Yankee Gas Services Company State of Connecticut, Department of Public Utility Control
Docket No. 6946 & 6988	Central Vermont Public Service Corporation Before the Vermont Public Service Board
Docket No. 04-035-42*	PacifiCorp Before the Public Service Commission of Utah
Docket No. 050045-EI*	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 05-03-17PH01	The Southern Connecticut Gas Company State of Connecticut, Department of Public Utility Control
Docket No. 050078-EI*	Progress Energy Florida, Inc. Before the Florida Public Service Commission
Docket No. 05-06-04	The United Illuminating Company State of Connecticut, Department of Public Utility Control
Docket No. A.05-08-021	San Gabriel Valley Water Company, Fontana Water Division Before the California Public Utilities Commission
Case No. 05-E-1222	New York State Electric & Gas Corporation Before the New York Public Service Commission
Docket No. 060038-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 05-11-008*	Southern California Edison Company and San Diego Gas & Electric Company

	Before the California Public Utilities
Commission	
Docket No. 06-035-21*	PacifiCorp Before the Public Service Commission of Utah
Docket No. 06-03-04* Phase I	Connecticut Natural Gas Corporation Connecticut Department of Public Utility Control
Application 06-05-025	Request for Order Authorizing the Sale by Thames GmbH of up to 100% of the Common Stock of American Water Works Company, Inc., Resulting in Change of Control of California-American Water Company Before the California Public Utilities Commission
Docket No. U-27703*	Atmos Energy Corporation d/b/a Trans Louisiana Gas Company Before the Louisiana Public Service Commission
Case Nos. 06-G-1185 And 06-G-1186*	KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island Before the New York Public Service
Commission	
Docket No. 06-12-02PH01*	Yankee Gas Services Company Connecticut Department of Public Utility Control
Case No. 06-G-1332* Inc.	Consolidated Edison Company of New York, Before the New York Public Service
Commission	
Formal Case No. 1016	Washington Gas Light Company Before the Public Service Commission of the District of Columbia
Docket No. 07-05-19	Aquarion Water Company of Connecticut

Connecticut Department of Public Utility Control

* Case Settled
** Testimony not filed/submitted due to settlement