BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION	)	
OF DELMARVA POWER & LIGHT COMPANY	)	
FOR AN INCREASE IN ELECTRIC BASE	)	PSC DOCKET NO. 10-237
RATES AND MISCELLANEOUS TARIFF	)	
CHANGES (FILED SEPTEMBER 18, 2009)	)	

Direct Testimony and Exhibits of Howard Solganick

On Behalf of the Staff of the Delaware Public Service Commission

October 28, 2010

Qualifications

Q. **Please state your name, position and business address.**

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047.

Q. **Please summarize your qualifications and experience.**

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning submetering and billing. I also previously served on two New Jersey Zoning Boards of Adjustment as Chairman and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 35 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony in utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand side management, capacity and system planning, and regulatory issues.

I have also led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects focused on the marketing, sale and delivery of retail energy, energy related products and services, and support services provided to utilities and retailers.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and have advised the Board of Directors of a public power utility consortium. For a period of four years I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and the Public Utilities Commission of Ohio. I also provided (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric rate cases.

I have also been engaged to review utility performance before, during and after outages resulting from major storms including Hurricane Ike.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998, I was a Managing Consultant for AT&T Solutions. From 1990 to 1994, I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held progressively increasing positions of responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice and implementation in both New Jersey and Pennsylvania.

Q. **Have you previously submitted testimony in regulatory proceedings?**

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies.

- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Direct Testimony

Q. **For whom are you appearing in this proceeding?**

A. I am appearing on behalf of the Staff of the Delaware Public Service Commission ("Staff").

Q. **What is the purpose of your testimony?**

A. My testimony analyzes the Company's Customer Class Cost of Service Study ("CCCOSS"); the proposed revenue allocation between classes; the proposed fixed variable rate design; and the supporting information provided and the miscellaneous tariff changes proposed by Delmarva Power & Light Company ("Company"). Based on my review of the Company's application and supporting testimony and the Company's responses to data requests, I have reached the following conclusions:

- The small $ 664,061 decrease in revenue requirements recommended by Staff witness Smith is best implemented through an across the board revenue allocation
- A modified fixed variable rate design that conforms to the Settlement Agreement in Docket No. 09-277T ("Gas Rate Design Settlement Agreement") should be implemented
- The modified fixed variable rate design provides revenue stability for the Company, which substantially reduces its risk, but the Company proposes a disproportionately small benefit to customers in the form of a 25 basis point reduction to the cost of equity[1]

Background

Q. Please summarize the Company's filing.

A. On July 2, 2010 the Company filed for an increase in base rates of $ 11.915 million. The filing included the required tariff sheets, a Customer Class Cost of Service Study ("CCCOSS"), a proposed revenue allocation, and a rate design consistent with the Gas Rate Design Settlement Agreement.

Subsequently on September 10, 2010 the Company updated its filing to reflect a full twelve month historic test year ending June 30, 2010, resulting in a new set of tariff sheets, a new CCCOSS, a revised revenue allocation and a new rate design consistent with the Gas Rate Design Settlement Agreement. This new filing is referred to as the "12+0 Update."

Subsequent to the 12+0 Update, the Company submitted an additional filing to removing certain costs and revenue requirements associated with its gas AMI project and requesting a $ 10.202 million revenue increase. This new filing is referred to as the "AMI Supplemental."

Cost of Service

Q. Has the Company provided a cost of service study?

A. The Company provided an updated CCCOSS for the distribution cost function based on the twelve month period ended June 30, 2010.[2]

Q. What is the purpose of a fully allocated cost of service study?

A. Just as the rate case process studies each element of the Company's operations to determine the overall cost to operate the Company efficiently and effectively, a fully allocated cost of service study attempts to

[1] Delmarva at 5:1-6 (Hanley Direct)
[2] Delmarva at 1:12-13 (Tanos Supplemental)

determine the individual cost to serve each customer class. The fully allocated cost of service study is intended to enable the Commission to allocate revenue requirements among customer classes.

Q. What is the unitized rate of return ("UROR")?

A. The UROR is the ratio of any class' rate of return to the rate of return of the utility. It is a useful barometer of how well individual classes compare to each other. Ideally, all customer classes would approach a UROR of 1.0.

Q. How does a Commission use the cost of service study?

A. Because customer classes use the utility's systems on an interrelated or shared basis, regulators have historically used a fully allocated cost of service study as a guideline to allocate revenue among classes. In some jurisdictions the regulators have established a "bandwidth" such as 0.90 to 1.10 for the UROR and consider rates that place any class within that bandwidth to be reasonable in light of the decisions made when developing a cost of service study. Additionally, when determining revenue allocation, regulators have a responsibility to consider not only the utility's financial condition and requirements, but also economic, social and other factors that may affect customers.

Q. Are there limitations to a cost of service study?

A. Yes, a cost of service study involves judgment and decisions on the part of the practitioner in making allocations among customer classes. In some cases, decisions are made to use a particular allocation factor for a particular account. In other cases, data used to develop an allocation factor are not always complete and/or timely and the practitioner must deal with the resulting uncertainty. Therefore, the cost of service study acts as a guide to revenue allocation and can be used to assist rate design.

Q. Are there other instances where the cost of service study may need to be adjusted or act only as a guide?

A. Yes, in situations where the utility or other parties have proposed tariff and/or operational changes that affect customer classes differently. Because a CCOSS is the result of an analysis at a specific point in time, in this case the test year ending June 30, 2010, the CCOSS will not be able to accurately predict the effects of the implementation of the new MFV rate design for the residential and general service classes.

Q. Have you reviewed the cost of service study presented by the Company's witness Mr. Tanos?

A. Yes. The CCCOSS included as Schedule EPT-1 Update for 12+0 is the detailed results that have been used for revenue allocation and rate design purposes by Mr. Janocha, and the unit costs and customer, demand and energy proportions calculated within the CCOSS are based on the overall rate of return requested by the Company.

The class values for the Demand, Commodity and Customer components shown on page 3 of Schedule EPT-2 Update 12+0 are somewhat different than the values shown on Schedule JFJ-3 but they can be used for the purpose of developing rates and to evaluate the overall rate impact of the various rate design proposals in this case.

Revenue Allocation

Q. Staff witness Smith has suggested a revenue decrease. How do you suggest that the decrease be allocated among the customer classes?

A. Due to the small nature of the Staff's recommended decrease, I suggest that the decrease be allocated "across the board" on a revenue basis. This revenue allocation avoids the potential for customer confusion when the rate order details a revenue reduction but a class receives an increase.

Using my revenue allocation methodology and recognizing that Staff has recommended a revenue decrease, my proposed revenue allocation for the modest decrease is as shown on Exhibit HS-2.

Q. What does the Company's CCCOSS demonstrate with regard to the relative rates of return of the various classes?

A. Under the Company's CCCOSS' assumptions, the Residential, Residential Heating, Large Volume General Service and the Lighting classes each has a UROR below 1.0, implying a return below the Company average. The other classes' URORs are above 1.0, implying a return above the Company average. None of the classes has a negative UROR, indicating that all classes contribute some return.

Q. What is the Company's suggestion for the allocation of a revenue increase?

A. The revenue allocation proposed by Company witness Janocha appears to have been driven by two primary considerations:

- Movement of all service classification URORs to 1.0 in a single rate change would require significant shifts in allocation of revenue requirements among service classifications and, consequently, would have large inter-class rate impacts. Therefore, customer impact should be considered as a balancing factor in any effort to achieve the goal of setting all service classification URORs at unity.[3]
- A general limitation that no service classification would experience an increase of more than 150% of the overall distribution percentage increase.[4]

Q. If the Commission grants a revenue increase, how do you suggest that it should be allocated?

A. In general I support Mr. Janocha's principles. The Company meets its general limitation of 150% for all classes when comparing the suggested distribution revenue class increases to the average distribution revenue increase (15.3). However, the general limitation is not met when comparing the suggested distribution revenue increase for the lighting classes (33.8%). Further while the Company is content to move the residential class from a UROR of 0.80 to 1.0 in this case (17.1% delivery revenue increase) it has decided to move the Large Volume Service class from a UROR of 0.80 to 0.96 (21.0% delivery revenue increase). I accept this difference as due to the 150% guideline.

Q. Using the several measures how would you change the Company's proposed revenue allocation?

[3] Delmarva at 4:23-5:5 (Janocha Direct)
[4] Delmarva at 5:6-8 (Janocha Direct)

A. Again, in the unlikely event that the Commission were to grant a substantial revenue increase I would use the results of the Company's CCCOSS for revenue allocation purposes.

I would allocate the revenue increase in a manner similar to the Company; however, I would limit the increase to the Lighting Service Classification.

Further, due to the small nature of the AMI increase proposed by the Company in its AMI Supplemental filing, I do not support the use of a separate allocation such as the use of Tables 3 and 4 in AMI Supplemental Schedule JFJ-1. Should the Commission disallow or defer the portion of Company's request related to its AMI efforts to date, Tables 3 and 4 should not be used.

Rate Design

Q. Have many of the parties to this case agreed to the implementation of a modified fixed variable ("MFV") rate design for residential and general service customers?

A. Yes. As a result of a settlement of various issues in the generic MFV rate design case, Docket 09-277T, the parties to that case agreed on the structure of the MFV rate design for this proceeding and executed a Gas Rate Design Settlement Agreement.

Q. Does the Company's rate design in this case meet the requirements of the Gas Rate Design Settlement Agreement?

A. The Company has proposed a MFV rate design for the residential and general service classes.

However, the Company's proposed definition of the Delivery Demand Contribution ("DDC") in Proposed Tariff Leaf No. 36b suggests that the DDC for both new customer premises and customers whose premise usage data in the period used to establish the DDC is insufficient to complete the DDC factor calculation will be assigned the class average DDC factor.

The Company proposal goes on to specify "Those customers will retain the class average usage factor until DDC Factors are reset as part of a succeeding gas delivery rate proceeding."

The Gas Rate Design Settlement Agreement defines the response to these two situations as "Those customers [with insufficient usage data] will retain the class average DDC factor until sufficient usage data is available to calculate a premise-specific DDC. New customer premises will be assigned the class average DDC Factor until sufficient usage data is available to calculate a premise-specific DDC."[5]

It appears that Company witness Janocha has correctly defined this (insufficient data) process in his supplemental testimony,[6] which means that Tariff Leaf No. 36b is in error.

I assume that the difference is a typographical error or a prior version of Tariff Leaf No. 36b and that the Company will amend its tariff filing.

Q. What are the positive aspects of a fixed variable rate design?

A. A fixed variable rate design better aligns costs and rates and reduces the cross-subsidization of various usage levels within a rate class. The fixed

[5] Settlement Agreement, Docket No. 09-277T, Paragraph 2d.
[6] Delmarva at 5:1-13 (Janocha Supplemental)

portion is designed to recover costs that are independent of demand or volume, such as customer service, metering and the service line.

For the utility, a fixed variable rate design provides better revenue stability and more predictable earnings when compared to a volumetric (usage) rate. Inherent in volumetric rates is the risk that weather will not be "normal," such as a warmer than normal heating season. A fixed variable rate design also mitigates business risk. As the economy suffers customers may reduce their consumption, which translates into a decrease in volumetric usage and related Company revenues.

For the customer, a fixed variable rate design provides better bill stability when compared to a volumetric rate. Inherent in volumetric rates is the risk that weather will not be "normal," such as a colder than normal heating season resulting in higher bills for delivery charges, which are relatively independent from weather.

Q. What are the negative aspects of a fixed variable rate design?

A. To the extent that a volumetric (usage) based rate design is replaced by a fixed variable rate design, customers that have not been paying their full cost of service will see an increase and customers in the opposite situation will see a decrease. The rate impact on a particular customer depends on the differences between the old volumetric-based rate and the fixed variable rate proposed.

Once a fixed variable rate design is in place a potential negative aspect is the customer's perception of how the demand charge operates, because most small customers have not yet been subjected to them. This perception can be negative if the utility does not clearly define how the demand charge is determined, when it will change and how the customer's behavior (usage and conservation) affects the demand level. A utility-sponsored customer education program that starts before the implementation of the new fixed variable rate design and continues with each update of the customer's demand level is crucial to obtaining customer understanding.

Q. Please summarize the Company's proposal for a fixed variable rate design.

A. The Company is proposing to implement the agreed-to MFV rate design for the residential and general service classes and has shifted the allocation of revenues from usage to demand and customer charges for the medium and large volume service classes.

The Company has added the required definition for Delivery Demand Contribution ("DDC") to the proposed tariff (Leaf No. 36a). The aggregate DDC calculation is also detailed in Schedule JFJ-3. The Company has updated Schedule JFJ-3 in its AMI Supplemental Testimony to reflect the use of January and February 2010 information. Before final rates are calculated, this schedule should be updated to reflect August 2010 and January and February 2011 information. The Company recognizes this and has indicated that it will update the schedule before the final rate implementation.[7]

Q. How did the Company develop its proposed fixed variable rate design?

A. Based upon the Gas Rate Design Settlement Agreement and the technical conferences that led to that agreement, the Company developed revenue

[7] Delmarva at 10:1-3 (Janocha Direct)

neutral MFV rate designs for the residential and general service classes.[8] For the medium and large volumes service classes the Company used the CCCOSS results shown in AMI Supplemental Schedule JFJ-2 that details the relative demand, commodity and customer portions of the class revenue.

The Company's Proposed Rates were derived through a direct calculation in the spreadsheet, which produced Schedule JFJ-4.

Q. How did the Company estimate and review the bill impact of the proposed fixed variable rate design for residential and general service customers?

A. Schedule JFJ-5 is a revenue-neutral analysis of the impact of the proposed rate design for customers without the moderation developed in support of the Settlement Agreement.

The Company provided Schedule JFJ-6 Update for 12+0 to detail the impact of a straight fixed variable rate design at the full customer charge level for a revenue neutral analysis (without a rate increase). This schedule highlighted that almost 15% of customers would see an average monthly bill impact of almost $6, which is in excess of 10%. The general service class would see an even greater impact.

The parties to the Gas Rate Design Settlement Agreement had recognized that the immediate transition to a full customer costs had an impact on low volume customers and during the technical conferences the concept of "modifying" the customer charge was explored and developed.

[8] Schedule JFJ-4 Update for AMI pages 1 and 2

The Company provided Schedule JFJ-7 Update for 12+0 to detail the impact of a modified fixed variable rate design at various customer charges. Pages 1 and 9 of this schedule demonstrates the value of moving to a MFV by limiting the increase in the customer charge to a level somewhat below full customer costs for the initial implementation of the MFV rate design.

The Company provided AMI Supplemental Schedule JFJ-8 to detail the impact of the MFV rate design at the Company's requested increase. As expected, the impact of the Company's requested increase and the implementation of the MFV rate design varies based upon a customer's consumption.

Q. How did you develop the rates for the residential and general service classifications?

A. The rates that I have developed are shown in Exhibit HS-3. The development of these rates is consistent with the Gas Rate Design Settlement Agreement and is similar to the Company's rate design. This exhibit is in the same form as Schedule JFJ-4 for consistency.

I have generated Exhibit HS-4 to evaluate the expected bill impact on residential and general service customers. This exhibit is in the same form as Schedule JFJ-8 for consistency. As expected, the impact of the Staff's proposed revenue decrease and the implementation of the MFV rate design varies based upon a customer's consumption.

Due to the lack of access to customer information, I cannot replicate the Company's Schedules JFJ-6 and 7, nor can I use the Company model to estimate the billing impact on customers of alternative MFV rate designs such as my proposed rate design based on Staff's revenue requirement.

Therefore my residential and general service rate design is an approximation due to the small decrease in each class' revenue that is obtained by proportionally reducing the revenue neutral MFV rate design.

When the Commission has made its revenue requirements determination, the Company should submit a compliance filing including the information provided in Schedules JFJ-6, 7 and 8 to ensure that no unexpected adverse impacts result from the final rate design. This compliance filing is very important if the Commission adopts the Gas Rate Design Settlement Agreement. The Company's affiliate PEPCO was ordered to and did provide a compliance filing as part of the implementation of its decoupling rate design.[9]

Q. How did you develop the rates for the medium and large volume general service classifications?

A. These service classifications are presently subject to rates that include a customer, demand and usage component. A fixed variable rate design minimizes the usage portion of the rates. Due to the small revenue decrease for these classes, I reduced the usage rate to achieve the required class revenue reduction. The rates that I have developed are shown in Exhibit HS-3. This exhibit is in the same form as Schedule JFJ-4 for consistency.

Q. Did you provide a rate impact analysis for the medium and large volume service classes?

A. I have generated Exhibit HS-4 to evaluate the expected bill impact on medium and large volume service customers. As expected, the impact of

[9] Formal Case No. 1053, District of Columbia Public Service Commission Order No. 15556, Attachment A.

the Staff's proposed revenue decrease and the implementation of the fixed variable rate design, which for these classes reduces the revenue collected from usage based charges, varies based upon a customer's consumption.

Q. Why is this analysis important for the medium and large volume service classes?

A. Although the rate form for medium and large volume customers has not changed the proportion of the revenue recovered from the usage charge has dropped from 22.1% and 15.3% respectively to 21.3% and 14.4% respectively, and the impact on customers within the class must be examined.

Q. How did you implement the revenue decrease for the Lighting class?

A. The rates that I have developed are shown in Exhibit HS-3. This exhibit is in the same form as Schedule JFJ-4 for consistency. This small class has a single rate, which was decreased proportionately to achieve the small revenue reduction.

Customer Communications

Q. How does the Company propose to explain the proposed fixed variable rate design to its customers?

A. The Gas Rate Design Settlement Agreement provides for the Company to develop communications plans to educate customers about the change to MFV-based rates before the implementation of those rates.[10] I understand that a collaborative process to monitor customer education is underway that includes the Company, Staff and the DPA.

[10] Settlement Agreement, Docket No. 09-277T, Paragraph 3.

Revenue Stability

Q. Have you analyzed the change in the revenue stability profile from the existing two part (customer and volumetric) rate design as compared to the proposed fixed variable (customer and demand) rate design?

A. Yes. I prepared Exhibit HS-5 to demonstrate the magnitude of the shift to stable and predictable revenue as compared to the more risky volumetric revenue that is subject to both weather and business risk. This exhibit uses the same revenue as Schedule JFJ-4. I added several columns and computed the percentage of revenue that is stable (that is, fixed on a customer basis) and the percentage that is subject to usage changing with weather and/or business conditions.

As shown in Exhibit HS-5 Column (4), at present only 30.2% of the residential delivery revenue, 18.6% of the general service delivery revenue, 77.9% of medium volume service delivery revenue and 84.7% of large volume service delivery revenue is stable. Overall, 31.6% of the Company's present delivery service revenue is stable. The remainder of the delivery revenue is exposed to usage risk. After the implementation of the MFV rate design, 100% of the Company's residential and general service delivery revenue will be stable on a per customer basis and in excess of 98% of the Company's overall delivery revenue will be stable.

Q. Does a MFV rate design have any effect on customer conservation?

A. The MFV rate design does not adversely impact any customer's incentive to conserve and/or make structural improvements to its home or business. Any reduction in consumption is directly accompanied by a reduction in the commodity charges. The commodity charge represents a significant majority of a customer's total bill.

However, the proposed rate design fixes the DDC between rate cases and will delay the distribution delivery portion of the conservation savings for the change in usage by a customer only until the Company's next rate case.

Q. Does the Company retain the conservation risk?

A. No. Moving the distribution delivery revenue recovery to the customer and DDC charges eliminates the Company's conservation risk between rate cases.

Analysis of the MFV Rate Design

Q. During the Commission's investigation (PSC Regulation Docket No. 59) of the interrelationship between rate design and energy efficiency and conservation, did the Staff develop criteria to evaluate a rate design?

A. Yes.[11]

Q. Does the MFV rate design satisfy Staff's criteria for a rate design?

A. I will address each of Staff's criteria in turn.

Rate Gradualism The Gas Rate Design Settlement Agreement and the process that developed it explored many variations of a straight fixed variable rate design and developed the MFV rate design as a transition to alleviate some of the impact of changing to a new rate structure. There

[11] Order No. 7420 Attachment A at 14.

are still intraclass impacts, because any transition between rate forms will have some impact, but the transition through the use of a MFV rate design minimizes the impact.

Customer Equity The use of both a Customer Charge and a DDC charge tailors the fixed variable rate to the customer's impact on the delivery system, as opposed to a one-size-fits-all flat monthly or annual charge for delivery service. However, the fixed DDC charge will provide a customer with a partially delayed (to the next rate case) price response to its conservation or operational changes.

Because each customer's bill is derived directly from its individual demand, no customer's rates are impacted by the conservation efforts of other customers between rate cases. This cross-subsidization of customers unable or unwilling to implement conservation measures (such as added insulation or new equipment) by customers that have the means or inclination to conserve has been a criticism of other decoupling mechanisms such as the Bill Stabilization Adjustment ("BSA") which remain focused on usage.

Impact on the Company's Risk Profile As detailed above, the Company's risk profile is significantly enhanced by shifting the usage-based revenue (with its inherent weather and business risk) to the fixed and increased customer charge and the fixed demand (DDC) component. The revenue per customer between rate cases is fixed.

Over/Under Earning Protection The Company's earnings are the net result of its revenues and expenses. The MFV rate design will have little or no impact or change on the Company's expenses. The proposed rate design will stabilize revenues and thus stabilize the Company's earnings much better than a rate structure with 68% of the revenue subject to usage risk.

Customer Service and Reliability Protection The proposed rate design should not affect the quality of the Company's customer service and reliability performance, nor should the existing performance standards be affected if a customer education program is implemented.

Miscellaneous Rate Design Issues

Q. Is there a difference in costs of service between full service and firm transportation service customers?

A. Yes. The present rates include a differential increased customer charge amounting to a differential of $275 per month. In response to a Staff data request asking the reasons for this differential, the Company provided a vague analysis from 2002 that does not clearly indicate the additional services provided to firm transportation customers that would justify this differential.[12] In this case the Company has not proposed to increase the $275 per month differential, which was approved in a previous proceeding; however, in light of the almost $150,000 being charged directly to firm transportation customers, the Company should be required to provide a study to support this differential in its next rate case.

Miscellaneous Tariff Changes

Q. Has the Company made changes to its tariff?

A. Yes. Some of the changes remove dates that were administratively important during prior transition periods and therefore should be accepted. The Company has also made typographical changes.

[12] Response to Data Request PSC-RD-14

However, the Company has proposed a number of changes to its tariff for which it has provided little or no support within the record.

For example, the Company is requesting a substantial increase (from $20 per MCF to $50 per MCF) in the penalty for an “Unauthorized Overrun,” which is the use of gas volumes in excess of 110% of the Contract MDQ. Similarly, the Company proposes increasing the penalty from $35 per MCF to $60 per MCF for exceeding a curtailment, a disconnection or an Operational Flow Order.[13]

The Company also proposes to add to Service Classification “GG” the language presently used to define and manage the Customer’s Contract Maximum Daily Quantity (“Contract MDQ”).[14]

Q. What is the purpose of the Unauthorized Overrun penalty?

A. A penalty should be designed to be high enough to gain the customer’s attention and ensure that the undesirable action does not occur. Under ideal conditions the Company would never have to collect the penalty. For this reason penalty amounts are usually not included within the change of revenue calculation.

The penalty presently in the Company’s tariff only applies to volumes in excess of 110% of the customer’s MDQ and therefore provides a “cushion” should the customer inadvertently exceed the MDQ due to an operating excursion. However, if a customer installed a substantial new piece of equipment or extensively expanded its facility the penalty could be activated.

[13] Proposed Delmarva Tariff Leaf Nos. 45 and 48.
[14] Proposed Delmarva Tariff Leaf No. 41a.

Q. Absent supporting testimony, how can the reasonableness of these proposed increases in the penalty be determined?

A. With no supporting information Staff is limited to comparing the Company's proposal to other similarly situated utilities. For this purpose I performed a high level review of the tariffs of PECO, PSEG, SJG, BGE and Chesapeake. The results of my review are summarized in Exhibit HS-6.

Exhibit HS-6 demonstrates that the Company's present unauthorized overrun penalty is lower than these other utilities, which can be reasonably presumed to have similar operating concerns due to weather and pipeline arrangements. The Company's penalty provision includes a 10% threshold or deadband, which none of the other utilities in my high-level survey has. At present the Transco Zone 6 non NY cost is approximately $4.00 per mmBTU.

Based upon this information I recommend that the penalty be increased to $30 per MCF. Concurrently, the Company should have the responsibility of notifying a customer within five working days if the customer has incurred the penalty more than once in any billing month.

Additionally, I recommend that the penalty for exceeding a curtailment, a disconnection or an Operational Flow Order should be raised to $50 per MCF, as the operational impacts on the Company are potentially greater.

Q. Is the Company's addition of the Contract MDQ language to Service Classification GG appropriate?

A. The Company has indicated that the language has been added to the Service Classification GG to define existing practice. Unless the Company is proposing to use Contract MDQ for the Design Day Contribution, in which case Tariff Leaf No. 37 has not been updated, Contract MDQ does not form the basis for charges for Service Classification GG customers and it does not provide for any penalties for exceeding the Contract MDQ for those customers.

It is unclear why the Company has added the Contract MDQ but has not provided for any reference to it within the tariff pages for Service Classification GG. Absent any definition of the use of the MDQ, its addition is inappropriate and could lead to confusion. Should the Contract MDQ use be defined by the Company, the term should be subject to certain customer protections. These protections should apply to all service classifications but are more important for smaller customers in Service Classification "GG."

Q. What customer protection are you proposing for the Customer MDQ?

A. The Company's definition of the operation of the Customer MDQ has three provisions:

1-Requests for increases in the customer's MDQ must be in writing and may not be granted if delivery system capacity is unavailable.

2-If delivery capacity is available the Company may increase the customer's MDQ without prior written notice for the current (and presumably following) billing months.

3-The Company will consider requests for reductions in the customer's MDQ based upon evidence of permanent changes in the customer's process or facility loads, if in the sole judgment of the Company, they are likely to continue for three years.

This definition appears to allow the Company to raise the customer's MDQ without notice when the contract level is exceeded, but requires the customer to petition for a reduction. The Company has a process in place to monitor the MDQ and compare the actual level to the customer's Contract MDQ and customers with measured MDQs below 70% of the Contract MDQ are brought to the attention of the appropriate account manager to review with the customer.[15]

I recommend that the Company be required to provide written notice (with an explanation of the impact on costs and delivery capability) to a customer if that customer's actual MDQ has been 80% or less than its contract MDQ for the twelve months ending June 30th. This would then give the customer two months to determine if it wished to request a lower MDQ and two months for the Company to respond. This change would ensure that all applicable customers will be provided with additional information about the effect of its usage. With this protection the MDQ adjustment process would become more balanced.

Q. Are the Company's billing determinants complete?

A. No. The Company has not accounted for the revenue derived from services provided such as Late Payment (Tariff Leaf No.10), Installment Payment (Tariff Leaf No.10), Restoration Charges (Tariff Leaf No.25) and Collection of Payment at Premise (Tariff Leaf No.25). While the Company is not seeking to change any of these rates, the complete billing determinants and revenue proof should be provided on rebuttal to demonstrate that the Company's revenue computation is correct.

Recommendations

Implementation of the MFV Rate Design

Q. When do you recommend that the new rates be implemented?

[15] Response to Data Request PSC-WA-1.

A. To avoid customer confusion for combination electric and gas customers, I recommend that the Commission order the Company to plan to implement its gas MFV rate design simultaneously with the electric MFV rate design. If the electric rate design has already been implemented as a result of Case No. 09-414, the new MFV gas rates should be implemented during a shoulder period.

Q. How do you recommend that the Commission recognize the value of the reduction in business risk of the proposed MFV rate design?

A. The MFV rate design offers the Company almost complete revenue stability compared to the existing rate structure. It also preserves the Company's opportunity to profit from any increases in the number of customers. It stabilizes revenue by employing the DDC charge as a form of a demand ratchet with a term equal to the period between rate cases. The MFV rate design does not include any caps and does not delay the recovery of revenue.

Therefore, I suggest that if the proposed rate design is implemented, the Company's allowed return on equity should be reduced concurrent with that change. As I noted previously, implementation of the MFV rate design as set forth in the Gas Rate Design Settlement Agreement will result in stabilizing more than 98% of the Company's overall delivery revenue.

Q. **Does this conclude your testimony?**

A. Yes.

Testimony - Howard Solganick

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.
Scope - “Witness Statement” on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program’s economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)

Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days.

Docket No: 10-237
Witness: Howard Solganick
Exhibit: HS-2

Delaware PSC Staff
Development of Proposed Gas Delivery Rates
Rate Class Allocation of Delivery Revenue Requirements

	Total Delaware Retail	Total Residential	General Service	Medium Volume Service	Large Volume Service	Lighting	Medium Volume Interruptible Service	Large Volume Interruptible Service
Test Period Delivery Revenue per Schedule JFJ-1 Update for AMI	$ 66,889,080	$ 43,001,115	$ 17,192,321	$ 2,915,550	$ 2,873,444	$ 710	$ 578,960	326,978
Staff Revenue Increase (per Exhibit RCS-1)	$ (664,061)							
Firm Service Classification Revenue Change	$ (664,061)	$ (432,768)	$ (173,025)	$ (29,342)	$ (28,919)	$ (7)		
Proposed Revenue	$ 66,225,019	$ 42,568,348	$ 17,019,296	$ 2,886,208	$ 2,844,525	$ 703	$ 578,960	$ 326,978
Revenue Change	-1.0% #	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%		

Docket No: 10-237
Witness: Howard Solganick
Exhibit: HS-3

Delaware PSC Staff
Development of Proposed Gas Delivery Rates
Residential Gas Service Rate Design
Actual Test Year Ending June 30, 2010 Determinants

Revenue Required $ 42,568,348

	Existing Rate Design			Proposed Rate Design					
Rate Element	Billing Determinants	Current Rate	Annualized Revenue	Billing Determinants	Revenue Neutral Rate Targets	Annualized Revenue at Revenue Neutral Rates	Recovery Allocation at Revenue Neutral Rates	Proposed Rate	Proposed Revenue
Customer Charge ($ per month)	1,356,454	$ 9.56	$ 12,967,700	1,356,454	$ 13.00	$ 17,633,902	0.4101	$ 12.87	$ 17,456,433
First 50 CCF Commodity Rate	39,492,299	$ 0.42101	$ 16,626,653						
Winter Over 50 CCF Commodity Rate	39,683,762	$ 0.33784	$ 13,406,762						
Design Day Contribution Rate ($ per CCF of DDC per Year)				12,021,483	$ 2.11016	$ 25,367,213	0.5899	$ 2.08892	$ 25,111,915
Total			$ 43,001,115			$ 43,001,115			$ 42,568,348

Docket No: 10-237
Witness: Howard Solganick
Exhibit: HS-3

Delaware PSC Staff
Development of Proposed Gas Delivery Rates
General Gas Service Rate Design
Actual Test Year Ending June 30, 2010 Determinants

Total $ 17,019,296

	Existing Rate Design			Proposed Rate Design					
Rate Element	**Billing Determinants**	**Current Rate**	**Annualized Revenue**	**Billing Determinants**	**Revenue Neutral Rate Targets**	**Annualized Revenue at Revenue Neutral Rates**	**Recovery Allocation at Revenue Neutral Rates**	**Proposed Rate**	**Proposed Revenue**
Customer Charge ($ per month)									
GG	112,681	$ 27.31	$ 3,077,318	112,681	$ 40.00	$ 4,507,240		$ 39.59	$ 4,460,754
GVFT	408	$ 302.31	$ 123,342	408	$ 315.00	$ 128,520		$ 314.59	$ 128,352
						$ 4,635,760	0.2696		$ 4,589,105
First 750 CCF Commodity Rate	20,819,001	$ 0.34975	$ 7,281,446						
Over 750 CCF Commodity Rate	25,685,033	$ 0.26125	$ 6,710,215						
Design Day Contribution Rate ($ per CCF of DDC per Month)				5,928,943	$ 2.11784	$ 12,556,561	0.7304	$ 2.09653	$ 12,430,190
Total			$ 17,192,321			$ 17,192,321			$ 17,019,295

Delaware PSC Staff
Development of Proposed Gas Delivery Rates
Medium Volume Gas (MVG) Service Rate Design
Medium Volume Firm Transportation Service
Actual Test Year Ending June 30, 2010 Determinants

Total	$	2,886,208
Customer	$	564,079
Demand	$	2,112,026
Commodity	$	210,103

	Rate Element	Billing Determinants		Current Rate		Annualized Revenue		Proposed Rate		Proposed Revenue
MVG										
	Customer Charge ($ per month)	339	$	419.27	$	142,133	$	419.27	$	142,133
	Demand MDQ MCF Rate	54,480	$	13.39	$	729,487	$	13.39	$	729,487
	Commodity MCF Rate	383,496	$	0.42979	$	164,823	$	0.41023	$	157,322
					$	1,036,442			$	1,028,941
MVFT										
	Customer Charge ($ per month)	390	$	694.27	$	270,765	$	694.27	$	270,765
	Demand MDQ MCF Rate	84,276	$	13.39	$	1,128,456	$	13.39	$	1,128,456
	Commodity MCF Rate	1,116,561	$	0.429790	$	479,887	$	0.41023	$	458,047
					$	1,879,108			$	1,857,268
	Total				$	2,915,550			$	2,886,209

Delaware PSC Staff
Development of Proposed Gas Delivery Rates
Large Volume Gas (LVG) Service Rate Design
Large Volume Firm Transportation Service
Actual Test Year Ending June 30, 2010 Determinants

Total	$	2,844,525
Customer	$	205,134
Demand	$	2,577,981
Commodity	$	61,411

	Rate Element	Billing Determinants	Current Rate	Annualized Revenue	Proposed Rate	Proposed Revenue
LVG						
	Customer Charge ($ per month)	24	$ 634.58	$ 15,230	$ 634.58	$ 15,230
	Demand MDQ MCF Rate	6,972	$ 8.24721	$ 57,500	$ 8.25	$ 57,500
	Commodity MCF Rate	165,787	$ 0.103390	$ 17,141	$ 0.09658	$ 16,012
				$ 89,870		$ 88,741
LVFT						
	Customer Charge ($ per month)	144	$ 909.58	$ 130,980	$ 909.58	$ 130,980
	Demand MDQ MCF Rate	270,492	$ 8.24721	$ 2,230,804	$ 8.25	$ 2,230,804
	Commodity MCF Rate	4,079,601	$ 0.103390	$ 421,790	$ 0.09658	$ 394,008
	Total			$ 2,783,574		$ 2,755,792
	Total			$ 2,873,444		$ 2,844,533

Delaware PSC Staff
Development of Proposed Gas Delivery Rates
Gas Lighting Sales Service (GL) Rate Design
Actual Test Year Ending June 30, 2010 Determinants

Total	$	703
Customer	$	703

Rate Element	Billing Determinants	Current Rate	Annualized Revenue	Proposed Rate	Proposed Revenue
Customer Charge ($ per month)	120	$ 5.92	$ 710	$ 5.86	$ 703
Total			$ 710		$ 703

Delaware PSC Staff
Residential Gas Service Classification
Bill Impact Analysis

Monthly Usage Levels (CCF)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Estimated DDC
60	60	48.6	29.4	12.9	7.7	5.7	5.1	5.3	8.7	18.1	35.1	3.71
80	80	64.8	39.2	17.2	10.3	7.6	6.9	7.0	11.6	24.2	46.8	4.95
100	100	81.0	48.9	21.5	12.9	9.5	8.6	8.8	14.5	30.2	58.5	6.19
120	120	97.3	58.7	25.8	15.5	11.4	10.3	10.5	17.4	36.3	70.1	7.43
140	140	113.5	68.5	30.1	18.0	13.3	12.0	12.3	20.3	42.3	81.8	8.67
160	160	129.7	78.3	34.4	20.6	15.3	13.7	14.1	23.2	48.3	93.5	9.91
180	180	145.9	88.1	38.7	23.2	17.2	15.4	15.8	26.1	54.4	105.2	11.14
200	200	162.1	97.9	43.0	25.8	19.1	17.2	17.6	29.1	60.4	116.9	12.38
300	300	243.1	146.8	64.5	38.6	28.6	25.7	26.4	43.6	90.6	175.4	18.57

Current Monthly Bill ($)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total Bill Current Rates
$ 90.49	$ 90.49	$ 75.82	$ 49.58	$ 27.13	$ 20.09	$ 17.36	$ 16.57	$ 16.74	$ 21.44	$ 34.26	$ 57.35	$ 517.32
$ 116.08	$ 116.08	$ 96.68	$ 62.92	$ 32.98	$ 23.60	$ 19.95	$ 18.91	$ 19.14	$ 25.40	$ 42.50	$ 73.29	$ 647.51
$ 141.67	$ 141.67	$ 117.41	$ 76.26	$ 38.84	$ 27.11	$ 22.55	$ 21.25	$ 21.53	$ 29.36	$ 50.73	$ 88.51	$ 776.89
$ 167.26	$ 167.26	$ 138.15	$ 88.87	$ 44.70	$ 30.62	$ 25.15	$ 23.59	$ 23.93	$ 33.31	$ 58.96	$ 103.47	$ 905.27
$ 192.85	$ 192.85	$ 158.89	$ 101.39	$ 50.55	$ 34.12	$ 27.75	$ 25.92	$ 26.32	$ 37.27	$ 67.20	$ 118.43	$ 1,033.56
$ 218.44	$ 218.44	$ 179.63	$ 113.92	$ 56.41	$ 37.63	$ 30.35	$ 28.26	$ 28.72	$ 41.23	$ 75.43	$ 133.39	$ 1,161.85
$ 244.03	$ 244.03	$ 200.37	$ 126.44	$ 62.26	$ 41.14	$ 32.95	$ 30.60	$ 31.11	$ 45.19	$ 83.30	$ 148.35	$ 1,289.78
$ 269.62	$ 269.62	$ 221.11	$ 138.97	$ 68.12	$ 44.65	$ 35.55	$ 32.94	$ 33.51	$ 49.15	$ 91.03	$ 163.31	$ 1,417.57
$ 397.57	$ 397.57	$ 324.81	$ 201.59	$ 96.20	$ 62.20	$ 48.54	$ 44.63	$ 45.48	$ 68.95	$ 129.69	$ 238.10	$ 2,055.31

Proposed Monthly Bill ($)

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total Bill Proposed Rates	Annual Total Bill Difference	Average Monthly Bill	Annual Total Bill Difference
$ 77.13	$ 77.13	$ 66.42	$ 48.28	$ 32.77	$ 27.90	$ 26.02	$ 25.47	$ 25.59	$ 28.84	$ 37.70	$ 53.66	$ 526.90	$ 9.58	$ 0.80	1.85%
$ 98.55	$ 98.55	$ 84.27	$ 60.09	$ 39.40	$ 32.91	$ 30.40	$ 29.68	$ 29.83	$ 34.16	$ 45.97	$ 67.25	$ 651.06	$ 3.54	$ 0.30	0.55%
$ 119.97	$ 119.97	$ 102.12	$ 71.89	$ 46.03	$ 37.93	$ 34.78	$ 33.88	$ 34.08	$ 39.48	$ 54.25	$ 80.85	$ 775.21	$ (1.67)	$ (0.14)	-0.22%
$ 141.39	$ 141.39	$ 119.97	$ 83.69	$ 52.67	$ 42.94	$ 39.16	$ 38.08	$ 38.32	$ 44.80	$ 62.53	$ 94.44	$ 899.37	$ (5.90)	$ (0.49)	-0.65%
$ 162.80	$ 162.80	$ 137.82	$ 95.50	$ 59.30	$ 47.95	$ 43.54	$ 42.28	$ 42.56	$ 50.12	$ 70.80	$ 108.04	$ 1,023.52	$ (10.03)	$ (0.84)	-0.97%
$ 184.22	$ 184.22	$ 155.67	$ 107.30	$ 65.93	$ 52.96	$ 47.93	$ 46.48	$ 46.80	$ 55.45	$ 79.08	$ 121.63	$ 1,147.68	$ (14.17)	$ (1.18)	-1.22%
$ 205.64	$ 205.64	$ 173.52	$ 119.11	$ 72.57	$ 57.97	$ 52.31	$ 50.69	$ 51.04	$ 60.77	$ 87.36	$ 135.23	$ 1,271.84	$ (17.94)	$ (1.50)	-1.39%
$ 227.06	$ 227.06	$ 191.37	$ 130.91	$ 79.20	$ 62.98	$ 56.69	$ 54.89	$ 55.28	$ 66.09	$ 95.63	$ 148.82	$ 1,395.99	$ (21.57)	$ (1.80)	-1.52%
$ 334.16	$ 334.16	$ 280.61	$ 189.93	$ 112.37	$ 88.04	$ 78.60	$ 75.90	$ 76.49	$ 92.70	$ 137.01	$ 216.80	$ 2,016.78	$ (38.54)	$ (3.21)	-1.88%

Delaware PSC Staff
GG Gas Service Classification
Bill Impact Analysis

Annual Average Bill Impact ($)
Non-Winter Usage (as a percentage of Average Winter Usage) -------->>

MONTHLY WINTER SALES (CCF)	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
0	$ 147.33	$ 147.33	$ 147.33	$ 147.33	$ 147.33	$ 147.33	$ 147.33	$ 147.33	$ 147.33	$ 147.33	$ 147.33
25	$ 151.16	$ 143.40	$ 135.64	$ 127.88	$ 120.13	$ 112.37	$ 104.61	$ 96.85	$ 89.09	$ 81.33	$ 73.57
50	$ 154.99	$ 139.47	$ 123.96	$ 108.44	$ 92.92	$ 77.40	$ 61.88	$ 46.37	$ 30.85	$ 15.33	$ (0.19)
75	$ 158.83	$ 135.56	$ 112.27	$ 88.99	$ 65.72	$ 42.44	$ 19.16	$ (4.12)	$ (27.39)	$ (50.67)	$ (73.96)
100	$ 162.66	$ 131.63	$ 100.59	$ 69.55	$ 38.51	$ 7.47	$ (23.56)	$ (54.60)	$ (85.63)	$ (116.68)	$ (147.72)
200	$ 178.00	$ 115.93	$ 53.85	$ (8.23)	$ (70.30)	$ (132.38)	$ (194.45)	$ (256.53)	$ (318.61)	$ (380.68)	$ (442.75)
300	$ 193.33	$ 100.23	$ 7.11	$ (86.00)	$ (179.12)	$ (272.23)	$ (365.34)	$ (458.45)	$ (551.57)	$ (644.68)	$ (737.80)
400	$ 208.67	$ 84.52	$ (39.63)	$ (163.78)	$ (287.94)	$ (412.08)	$ (536.24)	$ (660.39)	$ (784.54)	$ (908.69)	$ (1,032.84)
500	$ 224.00	$ 68.81	$ (86.38)	$ (241.56)	$ (396.75)	$ (551.94)	$ (707.13)	$ (862.32)	$ (1,017.50)	$ (1,172.69)	$ (1,327.88)
1000	$ 411.30	$ 100.93	$ (209.45)	$ (519.83)	$ (830.20)	$ (1,140.58)	$ (1,450.96)	$ (1,761.33)	$ (2,040.74)	$ (2,289.17)	$ (2,537.59)
1500	$ 709.23	$ 243.67	$ (221.90)	$ (687.46)	$ (1,153.03)	$ (1,618.60)	$ (1,991.23)	$ (2,363.88)	$ (2,736.52)	$ (3,109.16)	$ (3,481.80)
2000	$ 1,007.16	$ 386.40	$ (234.35)	$ (855.10)	$ (1,444.89)	$ (1,941.74)	$ (2,438.59)	$ (2,935.44)	$ (3,432.31)	$ (3,929.16)	$ (4,426.01)
2500	$ 1,305.09	$ 529.15	$ (246.80)	$ (1,022.75)	$ (1,643.82)	$ (2,264.88)	$ (2,885.95)	$ (3,507.02)	$ (4,128.09)	$ (4,749.15)	$ (5,370.22)
3000	$ 1,603.01	$ 671.88	$ (259.25)	$ (1,097.46)	$ (1,842.74)	$ (2,588.03)	$ (3,333.31)	$ (4,078.59)	$ (4,823.87)	$ (5,569.15)	$ (6,314.43)
3500	$ 1,900.94	$ 814.62	$ (271.70)	$ (1,172.17)	$ (2,041.67)	$ (2,911.17)	$ (3,780.66)	$ (4,650.15)	$ (5,519.65)	$ (6,389.15)	$ (7,258.64)
4000	$ 2,198.86	$ 957.36	$ (253.18)	$ (1,246.89)	$ (2,240.60)	$ (3,234.31)	$ (4,228.01)	$ (5,221.73)	$ (6,215.43)	$ (7,209.15)	$ (8,202.86)
4500	$ 2,496.79	$ 1,100.10	$ (203.67)	$ (1,321.60)	$ (2,439.52)	$ (3,557.45)	$ (4,675.37)	$ (5,793.29)	$ (6,911.22)	$ (8,029.14)	$ (9,147.07)
5000	$ 2,794.71	$ 1,242.83	$ (154.18)	$ (1,396.32)	$ (2,638.45)	$ (3,880.60)	$ (5,122.73)	$ (6,364.87)	$ (7,607.00)	$ (8,849.14)	$ (10,091.28)
6000	$ 3,390.57	$ 1,528.31	$ (55.18)	$ (1,545.75)	$ (3,036.31)	$ (4,526.87)	$ (6,017.44)	$ (7,508.00)	$ (8,998.57)	$ (10,489.13)	$ (11,979.70)
7000	$ 3,986.42	$ 1,813.79	$ 43.82	$ (1,695.17)	$ (3,434.17)	$ (5,173.16)	$ (6,912.15)	$ (8,651.14)	$ (10,390.14)	$ (12,129.12)	$ (13,868.12)
8000	$ 4,582.27	$ 2,130.23	$ 142.81	$ (1,844.60)	$ (3,832.02)	$ (5,819.44)	$ (7,806.86)	$ (9,794.29)	$ (11,781.70)	$ (13,769.12)	$ (15,756.54)
9000	$ 5,178.13	$ 2,477.66	$ 241.81	$ (1,994.04)	$ (4,229.88)	$ (6,465.73)	$ (8,701.57)	$ (10,937.42)	$ (13,173.27)	$ (15,409.11)	$ (17,644.96)
10000	$ 5,773.98	$ 2,825.09	$ 340.81	$ (2,143.46)	$ (4,627.74)	$ (7,112.01)	$ (9,596.28)	$ (12,080.56)	$ (14,564.83)	$ (17,049.11)	$ (19,533.38)
12000	$ 6,965.69	$ 3,519.94	$ 538.81	$ (2,442.32)	$ (5,423.45)	$ (8,404.58)	$ (11,385.71)	$ (14,366.83)	$ (17,347.97)	$ (20,329.10)	$ (23,310.22)
14000	$ 8,157.39	$ 4,214.79	$ 736.80	$ (2,741.18)	$ (6,219.17)	$ (9,697.15)	$ (13,175.13)	$ (16,653.12)	$ (20,131.10)	$ (23,609.09)	$ (27,087.07)
16000	$ 9,349.10	$ 4,909.64	$ 934.80	$ (3,040.04)	$ (7,014.87)	$ (10,989.71)	$ (14,964.56)	$ (18,939.39)	$ (22,914.23)	$ (26,889.07)	$ (30,863.91)
18000	$ 10,540.81	$ 5,604.49	$ 1,132.79	$ (3,338.89)	$ (7,810.59)	$ (12,282.28)	$ (16,753.98)	$ (21,225.67)	$ (25,697.36)	$ (30,169.06)	$ (34,640.75)
20000	$ 11,732.51	$ 6,299.34	$ 1,330.79	$ (3,637.75)	$ (8,606.30)	$ (13,574.85)	$ (18,543.40)	$ (23,511.95)	$ (28,480.50)	$ (33,449.04)	$ (38,417.59)

Annual Average Bill Impact (%)
Non-Winter Usage (as a percentage of Average Winter Usage) -------->>

MONTHLY WINTER SALES (CCF)	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
0	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
25	31.1%	28.3%	25.6%	23.2%	20.9%	18.9%	16.9%	15.1%	13.5%	11.9%	10.4%
50	24.1%	20.3%	16.9%	14.0%	11.3%	9.0%	6.8%	4.9%	3.1%	1.5%	0.0%
75	19.8%	15.6%	12.0%	8.9%	6.2%	3.7%	1.6%	-0.3%	-2.1%	-3.6%	-5.1%
100	17.0%	12.6%	8.9%	5.7%	2.9%	0.5%	-1.6%	-3.5%	-5.1%	-6.7%	-8.0%
200	11.2%	6.6%	2.8%	-0.4%	-3.1%	-5.4%	-7.3%	-9.1%	-10.6%	-12.0%	-13.2%
300	8.7%	4.0%	0.3%	-2.9%	-5.5%	-7.7%	-9.6%	-11.2%	-12.7%	-14.0%	-15.1%
400	7.3%	2.6%	-1.1%	-4.2%	-6.7%	-8.9%	-10.8%	-12.4%	-13.8%	-15.1%	-16.2%
500	6.4%	1.8%	-2.0%	-5.0%	-7.6%	-9.7%	-11.5%	-13.1%	-14.5%	-15.7%	-16.8%
1,000	6.3%	1.4%	-2.5%	-5.7%	-8.3%	-10.4%	-12.3%	-13.9%	-15.0%	-15.9%	-16.7%
1,500	7.5%	2.3%	-1.8%	-5.1%	-7.8%	-10.1%	-11.5%	-12.7%	-13.8%	-14.8%	-15.6%
2,000	8.1%	2.7%	-1.5%	-4.8%	-7.4%	-9.2%	-10.7%	-12.0%	-13.2%	-14.2%	-15.1%
2,500	8.5%	3.0%	-1.2%	-4.7%	-6.8%	-8.7%	$\boxed{-10.3\%}$	-11.6%	-12.8%	-13.9%	-14.8%
3,000	8.8%	3.2%	-1.1%	-4.2%	-6.4%	-8.3%	-9.9%	-11.3%	-12.5%	-13.6%	-14.6%
3,500	9.0%	3.4%	-1.0%	-3.9%	-6.2%	-8.1%	-9.7%	-11.1%	-12.4%	-13.4%	-14.4%
4,000	9.1%	3.5%	-0.8%	-3.6%	-5.9%	-7.9%	-9.5%	-11.0%	-12.2%	-13.3%	-14.3%
4,500	9.2%	3.5%	-0.6%	-3.4%	-5.8%	-7.7%	-9.4%	-10.8%	-12.1%	-13.2%	-14.2%
5,000	9.3%	3.6%	-0.4%	-3.3%	-5.6%	-7.6%	-9.3%	-10.7%	-12.0%	-13.1%	-14.1%
6,000	9.5%	3.7%	-0.1%	-3.0%	-5.4%	-7.4%	-9.1%	-10.6%	-11.9%	-13.0%	-14.0%
7,000	9.6%	3.8%	0.1%	-2.9%	-5.3%	-7.3%	-9.0%	-10.5%	-11.8%	-12.9%	-13.9%
8,000	9.6%	3.9%	0.2%	-2.7%	-5.2%	-7.2%	-8.9%	-10.4%	-11.7%	-12.8%	-13.8%
9,000	9.7%	4.0%	0.4%	-2.6%	-5.1%	-7.1%	-8.9%	-10.3%	-11.6%	-12.8%	-13.8%
10,000	9.7%	4.2%	0.4%	-2.5%	-5.0%	-7.0%	-8.8%	-10.3%	-11.6%	-12.7%	-13.8%
12,000	9.8%	4.3%	0.6%	-2.4%	-4.9%	-7.0%	-8.7%	-10.2%	-11.5%	-12.7%	-13.7%
14,000	9.8%	4.4%	0.7%	-2.3%	-4.8%	-6.9%	-8.7%	-10.2%	-11.5%	-12.6%	-13.7%
16,000	9.9%	4.5%	0.8%	-2.3%	-4.8%	-6.8%	-8.6%	-10.1%	-11.4%	-12.6%	-13.6%
18,000	9.9%	4.6%	0.8%	-2.2%	-4.7%	-6.8%	-8.6%	-10.1%	-11.4%	-12.6%	-13.6%
20,000	9.9%	4.7%	0.9%	-2.2%	-4.7%	-6.8%	-8.5%	-10.1%	-11.4%	-12.6%	-13.6%

Delaware PSC Staff
Medium Volume Service Classification
Bill Impact Analysis

Monthly Sales (MCF)	MDQ	Load Factor	SUMMER - TOTAL BILL Present Base	Present GCR	Present Total	Proposed Base	Proposed GCR	Proposed Total	Difference	
500	66	25	$1,528	$4,582	$6,110	$1,518	$4,582	$6,100	-$10	-0.2%
500	33	50	$1,086	$4,268	$5,344	$1,077	$4,268	$5,344	$1	0.0%
500	22	75	$939	$4,163	$5,092	$929	$4,163	$5,092	$1	0.0%
1,000	132	25	$2,637	$9,164	$11,780	$2,618	$9,164	$11,781	$1	0.0%
1,000	66	50	$1,753	$8,536	$10,268	$1,734	$8,536	$10,269	$1	0.0%
1,000	44	75	$1,459	$8,326	$9,784	$1,439	$8,326	$9,766	$1	0.0%
2,000	263	25	$4,842	$18,318	$23,118	$4,802	$18,318	$23,120	$2	0.0%
2,000	132	50	$3,087	$17,071	$20,118	$3,048	$17,071	$20,120	$2	0.0%
2,000	88	75	$2,498	$16,653	$19,110	$2,459	$16,653	$19,112	$2	0.0%
3,000	395	25	$7,059	$27,481	$34,479	$7,001	$27,481	$34,482	$3	0.0%
3,000	197	50	$4,408	$25,597	$29,944	$4,350	$25,597	$29,947	$3	0.0%
3,000	132	75	$3,538	$24,979	$28,455	$3,479	$24,979	$28,458	$3	0.0%
4,000	526	25	$9,264	$36,635	$45,817	$9,186	$36,635	$45,821	$4	0.0%
4,000	263	50	$5,742	$34,133	$39,793	$5,664	$34,133	$39,797	$4	0.0%
4,000	175	75	$4,564	$33,296	$37,777	$4,486	$33,296	$37,781	$4	0.0%
5,000	658	25	$11,482	$45,799	$57,178	$11,384	$45,799	$57,183	$5	0.0%
5,000	329	50	$7,076	$42,669	$49,642	$6,979	$42,669	$49,647	$5	0.0%
5,000	219	75	$5,604	$41,622	$47,122	$5,506	$41,622	$47,128	$5	0.0%
6,000	789	25	$13,686	$54,953	$68,516	$13,569	$54,953	$68,522	$6	0.0%
6,000	395	50	$8,411	$51,204	$59,491	$8,293	$51,204	$59,497	$6	0.0%
6,000	263	75	$6,643	$49,948	$56,468	$6,526	$49,948	$56,474	$6	0.0%
7,000	921	25	$15,904	$64,117	$79,877	$15,767	$64,117	$79,884	$7	0.0%
7,000	461	50	$9,745	$59,740	$69,340	$9,608	$59,740	$69,347	$7	0.0%
7,000	307	75	$7,683	$58,274	$65,813	$7,546	$58,274	$65,820	$7	0.0%
8,000	1,053	25	$18,122	$73,280	$91,238	$17,965	$73,280	$91,246	$8	0.0%
8,000	526	50	$11,065	$68,266	$79,167	$10,909	$68,266	$79,175	$8	0.0%
8,000	351	75	$8,722	$66,601	$75,158	$8,566	$66,601	$75,166	$8	0.0%
9,000	1,184	25	$20,326	$82,434	$102,576	$20,150	$82,434	$102,585	$9	0.0%
9,000	592	50	$12,399	$76,801	$89,016	$12,223	$76,801	$89,025	$9	0.0%
9,000	395	75	$9,762	$74,927	$84,503	$9,586	$74,927	$84,513	$9	0.0%
10,000	1,316	25	$22,544	$91,598	$113,936	$22,349	$91,598	$113,947	$10	0.0%
10,000	658	50	$13,734	$85,337	$98,865	$13,538	$85,337	$98,875	$10	0.0%
10,000	439	75	$10,801	$83,253	$93,849	$10,606	$83,253	$93,859	$10	0.0%

Monthly Sales (MCF)	MDQ	Load Factor	WINTER - TOTAL BILL Present Base	Present GCR	Present Total	Proposed Base	Proposed GCR	Proposed Total	Difference		ANNUAL IMPACT - TOTAL BILL Current	Proposed	Difference	
500	66	25	$1,528	$4,582	$6,110	$1,518	$4,582	$6,100	-$10	-0.2%	$73,320	$73,203	-$117	-0.2%
500	33	50	$1,086	$4,268	$5,354	$1,077	$4,268	$5,344	-$10	-0.2%	$64,208	$64,132	-$76	-0.1%
500	22	75	$939	$4,163	$5,102	$929	$4,163	$5,092	-$10	-0.2%	$61,185	$61,109	-$76	-0.1%
1,000	132	25	$2,637	$9,164	$11,801	$2,618	$9,164	$11,781	-$20	-0.2%	$141,526	$141,374	-$152	-0.1%
1,000	66	50	$1,753	$8,536	$10,289	$1,734	$8,536	$10,269	-$20	-0.2%	$123,385	$123,233	-$152	-0.1%
1,000	44	75	$1,459	$8,326	$9,785	$1,439	$8,326	$9,766	-$20	-0.2%	$117,339	$117,186	-$152	-0.1%
2,000	263	25	$4,842	$18,318	$23,159	$4,802	$18,318	$23,120	-$39	-0.2%	$277,747	$277,442	-$305	-0.1%
2,000	132	50	$3,087	$17,071	$20,159	$3,048	$17,071	$20,120	-$39	-0.2%	$241,740	$241,435	-$305	-0.1%
2,000	88	75	$2,498	$16,653	$19,151	$2,459	$16,653	$19,112	-$39	-0.2%	$229,646	$229,341	-$305	-0.1%
3,000	395	25	$7,059	$27,481	$34,541	$7,001	$27,481	$34,482	-$59	-0.2%	$414,242	$413,785	-$457	-0.1%
3,000	197	50	$4,408	$25,597	$30,006	$4,350	$25,597	$29,947	-$59	-0.2%	$359,819	$359,362	-$457	-0.1%
3,000	132	75	$3,538	$24,979	$28,517	$3,479	$24,979	$28,458	-$59	-0.2%	$341,953	$341,496	-$457	-0.1%
4,000	526	25	$9,264	$36,635	$45,899	$9,186	$36,635	$45,821	-$78	-0.2%	$550,462	$549,853	-$610	-0.1%
4,000	263	50	$5,742	$34,133	$39,875	$5,664	$34,133	$39,797	-$78	-0.2%	$478,173	$477,564	-$610	-0.1%
4,000	175	75	$4,564	$33,296	$37,860	$4,486	$33,296	$37,781	-$78	-0.2%	$453,985	$453,376	-$610	-0.1%
5,000	658	25	$11,482	$45,799	$57,281	$11,384	$45,799	$57,183	-$98	-0.2%	$686,957	$686,195	-$762	-0.1%
5,000	329	50	$7,076	$42,669	$49,745	$6,979	$42,669	$49,647	-$98	-0.2%	$596,528	$595,766	-$762	-0.1%
5,000	219	75	$5,604	$41,622	$47,225	$5,506	$41,622	$47,128	-$98	-0.2%	$566,293	$565,531	-$762	-0.1%
6,000	789	25	$13,686	$54,953	$68,639	$13,569	$54,953	$68,522	-$117	-0.2%	$823,178	$822,263	-$914	-0.1%
6,000	395	50	$8,411	$51,204	$59,615	$8,293	$51,204	$59,497	-$117	-0.2%	$714,882	$713,967	-$914	-0.1%
6,000	263	75	$6,643	$49,948	$56,591	$6,526	$49,948	$56,474	-$117	-0.2%	$678,600	$677,686	-$914	-0.1%
7,000	921	25	$15,904	$64,117	$80,021	$15,767	$64,117	$79,884	-$137	-0.2%	$959,673	$958,606	-$1,067	-0.1%
7,000	461	50	$9,745	$59,740	$69,484	$9,608	$59,740	$69,347	-$137	-0.2%	$833,236	$832,169	-$1,067	-0.1%
7,000	307	75	$7,683	$58,274	$65,957	$7,546	$58,274	$65,820	-$137	-0.2%	$790,907	$789,840	-$1,067	-0.1%
8,000	1,053	25	$18,122	$73,280	$91,402	$17,965	$73,280	$91,246	-$156	-0.2%	$1,096,168	$1,094,949	-$1,219	-0.1%
8,000	526	50	$11,065	$68,266	$79,331	$10,909	$68,266	$79,175	-$156	-0.2%	$951,315	$950,096	-$1,219	-0.1%
8,000	351	75	$8,722	$66,601	$75,323	$8,566	$66,601	$75,166	-$156	-0.2%	$903,215	$901,996	-$1,219	-0.1%
9,000	1,184	25	$20,326	$82,434	$102,761	$20,150	$82,434	$102,585	-$176	-0.2%	$1,232,388	$1,231,017	-$1,372	-0.1%
9,000	592	50	$12,399	$76,801	$89,201	$12,223	$76,801	$89,025	-$176	-0.2%	$1,069,670	$1,068,298	-$1,372	-0.1%
9,000	395	75	$9,762	$74,927	$84,689	$9,586	$74,927	$84,513	-$176	-0.2%	$1,015,522	$1,014,150	-$1,372	-0.1%
10,000	1,316	25	$22,544	$91,598	$114,142	$22,349	$91,598	$113,947	-$196	-0.2%	$1,368,883	$1,367,359	-$1,524	-0.1%
10,000	658	50	$13,734	$85,337	$99,071	$13,538	$85,337	$98,875	-$196	-0.2%	$1,188,024	$1,186,500	-$1,524	-0.1%
10,000	439	75	$10,801	$83,253	$94,054	$10,606	$83,253	$93,859	-$196	-0.2%	$1,127,829	$1,126,305	-$1,524	-0.1%

Delaware PSC Staff
Large Volume Service Classification
Bill Impact Analysis

Monthly Sales (MCF)	MDQ	Load Factor	SUMMER - TOTAL BILL Present Base	Present GCR	Present Total	Proposed Base	Proposed GCR	Proposed Total	Difference	
5.000	658	25	$6.681	$45.799	$52.480	$6.647	$45.799	$52.446	-$34	-0.1%
5.000	329	50	$3.968	$42.669	$46.636	$3.934	$42.669	$46.602	-$34	-0.1%
5.000	219	75	$3.061	$41.622	$44.682	$3.027	$41.622	$44.648	-$34	-0.1%
10.000	1.316	25	$12.728	$91.598	$104.326	$12.660	$91.598	$104.258	-$68	-0.1%
10.000	658	50	$7.301	$85.337	$92.638	$7.233	$85.337	$92.570	-$68	-0.1%
10.000	439	75	$5.495	$83.253	$88.748	$5.427	$83.253	$88.680	-$68	-0.1%
15.000	1.974	25	$18.774	$137.397	$156.171	$18.672	$137.397	$156.069	-$102	-0.1%
15.000	987	50	$10.634	$128.006	$138.640	$10.532	$128.006	$138.537	-$102	-0.1%
15.000	658	75	$7.921	$124.875	$132.796	$7.819	$124.875	$132.694	-$102	-0.1%
20.000	2.632	25	$24.821	$183.196	$208.017	$24.684	$183.196	$207.880	-$136	-0.1%
20.000	1.316	50	$13.967	$170.674	$184.641	$13.831	$170.674	$184.505	-$136	-0.1%
20.000	877	75	$10.347	$166.497	$176.844	$10.211	$166.497	$176.707	-$136	-0.1%
25.000	3.289	25	$30.859	$228.985	$259.844	$30.689	$228.985	$259.674	-$170	-0.1%
25.000	1.645	50	$17.300	$213.343	$230.643	$17.130	$213.343	$230.473	-$170	-0.1%
25.000	1.096	75	$12.773	$208.119	$220.891	$12.603	$208.119	$220.721	-$170	-0.1%
30.000	3.947	25	$36.905	$274.784	$311.690	$36.701	$274.784	$311.486	-$204	-0.1%
30.000	1.974	50	$20.634	$256.011	$276.645	$20.429	$256.011	$276.440	-$204	-0.1%
30.000	1.316	75	$15.207	$249.750	$264.957	$15.003	$249.750	$264.753	-$204	-0.1%
35.000	4.605	25	$42.952	$320.584	$363.535	$42.714	$320.584	$363.297	-$238	-0.1%
35.000	2.303	50	$23.967	$298.680	$322.646	$23.729	$298.680	$322.408	-$238	-0.1%
35.000	1.535	75	$17.633	$291.372	$309.005	$17.395	$291.372	$308.766	-$238	-0.1%
40.000	5.263	25	$48.998	$366.383	$415.381	$48.726	$366.383	$415.109	-$272	-0.1%
40.000	2.632	50	$27.300	$341.348	$368.648	$27.028	$341.348	$368.376	-$272	-0.1%
40.000	1.754	75	$20.059	$332.994	$353.053	$19.787	$332.994	$352.780	-$272	-0.1%
50.000	6.579	25	$61.091	$457.981	$519.072	$60.751	$457.981	$518.731	-$341	-0.1%
50.000	3.289	50	$33.958	$426.675	$460.634	$33.618	$426.675	$460.293	-$341	-0.1%
50.000	2.193	75	$24.919	$416.247	$441.166	$24.579	$416.247	$440.826	-$341	-0.1%
60.000	7.895	25	$73.185	$549.579	$622.763	$72.776	$549.579	$622.354	-$409	-0.1%
60.000	3.947	50	$40.625	$512.012	$552.637	$40.216	$512.012	$552.228	-$409	-0.1%
60.000	2.632	75	$29.779	$499.500	$529.279	$29.371	$499.500	$528.871	-$409	-0.1%
70.000	9.211	25	$85.278	$641.177	$726.454	$84.801	$641.177	$725.977	-$477	-0.1%
70.000	4.605	50	$47.291	$597.350	$644.640	$46.814	$597.350	$644.164	-$477	-0.1%
70.000	3.070	75	$34.631	$582.744	$617.375	$34.155	$582.744	$616.898	-$477	-0.1%

Monthly Sales (MCF)	MDQ	Load Factor	WINTER - TOTAL BILL Present Base	Present GCR	Present Total	Proposed Base	Proposed GCR	Proposed Total	Difference	
5.000	658	25	$6.681	$45.799	$52.480	$6.647	$45.799	$52.446	($34)	-0.1%
5.000	329	50	$3.968	$42.669	$46.636	$3.934	$42.669	$46.602	($34)	-0.1%
5.000	219	75	$3.061	$41.622	$44.682	$3.027	$41.622	$44.648	($34)	-0.1%
10.000	1.316	25	$12.728	$91.598	$104.326	$12.660	$91.598	$104.258	($68)	-0.1%
10.000	658	50	$7.301	$85.337	$92.638	$7.233	$85.337	$92.570	($68)	-0.1%
10.000	439	75	$5.495	$83.253	$88.748	$5.427	$83.253	$88.680	($68)	-0.1%
15.000	1.974	25	$18.774	$137.397	$156.171	$18.672	$137.397	$156.069	($102)	-0.1%
15.000	987	50	$10.634	$128.006	$138.640	$10.532	$128.006	$138.537	($102)	-0.1%
15.000	658	75	$7.921	$124.875	$132.796	$7.819	$124.875	$132.694	($102)	-0.1%
20.000	2.632	25	$24.821	$183.196	$208.017	$24.684	$183.196	$207.880	($136)	-0.1%
20.000	1.316	50	$13.967	$170.674	$184.641	$13.831	$170.674	$184.505	($136)	-0.1%
20.000	877	75	$10.347	$166.497	$176.844	$10.211	$166.497	$176.707	($136)	-0.1%
25.000	3.289	25	$30.859	$228.985	$259.844	$30.689	$228.985	$259.674	($170)	-0.1%
25.000	1.645	50	$17.300	$213.343	$230.643	$17.130	$213.343	$230.473	($170)	-0.1%
25.000	1.096	75	$12.773	$208.119	$220.891	$12.603	$208.119	$220.721	($170)	-0.1%
30.000	3.947	25	$36.905	$274.784	$311.690	$36.701	$274.784	$311.486	($204)	-0.1%
30.000	1.974	50	$20.634	$256.011	$276.645	$20.429	$256.011	$276.440	($204)	-0.1%
30.000	1.316	75	$15.207	$249.750	$264.957	$15.003	$249.750	$264.753	($204)	-0.1%
35.000	4.605	25	$42.952	$320.584	$363.535	$42.714	$320.584	$363.297	($238)	-0.1%
35.000	2.303	50	$23.967	$298.680	$322.646	$23.729	$298.680	$322.408	($238)	-0.1%
35.000	1.535	75	$17.633	$291.372	$309.005	$17.395	$291.372	$308.766	($238)	-0.1%
40.000	5.263	25	$48.998	$366.383	$415.381	$48.726	$366.383	$415.109	($272)	-0.1%
40.000	2.632	50	$27.300	$341.348	$368.648	$27.028	$341.348	$368.376	($272)	-0.1%
40.000	1.754	75	$20.059	$332.994	$353.053	$19.787	$332.994	$352.780	($272)	-0.1%
50.000	6.579	25	$61.091	$457.981	$519.072	$60.751	$457.981	$518.731	($341)	-0.1%
50.000	3.289	50	$33.958	$426.675	$460.634	$33.618	$426.675	$460.293	($341)	-0.1%
50.000	2.193	75	$24.919	$416.247	$441.166	$24.579	$416.247	$440.826	($341)	-0.1%
60.000	7.895	25	$73.185	$549.579	$622.763	$72.776	$549.579	$622.354	($409)	-0.1%
60.000	3.947	50	$40.625	$512.012	$552.637	$40.216	$512.012	$552.228	($409)	-0.1%
60.000	2.632	75	$29.779	$499.500	$529.279	$29.371	$499.500	$528.871	($409)	-0.1%
70.000	9.211	25	$85.278	$641.177	$726.454	$84.801	$641.177	$725.977	($477)	-0.1%
70.000	4.605	50	$47.291	$597.350	$644.640	$46.814	$597.350	$644.164	($477)	-0.1%
70.000	3.070	75	$34.631	$582.744	$617.375	$34.155	$582.744	$616.898	($477)	-0.1%

Monthly Sales (MCF)	MDQ	Load Factor	ANNUAL IMPACT - TOTAL BILL Present	Proposed	Difference	
5.000	658	25	$629.761	$629.352	-$409	-0.1%
5.000	329	50	$559.635	$559.227	-$409	-0.1%
5.000	219	75	$536.189	$535.780	-$409	-0.1%
10.000	1.316	25	$1.251.907	$1.251.090	-$817	-0.1%
10.000	658	50	$1.111.655	$1.110.838	-$817	-0.1%
10.000	439	75	$1.064.976	$1.064.159	-$817	-0.1%
15.000	1.974	25	$1.874.053	$1.872.828	-$1.226	-0.1%
15.000	987	50	$1.663.676	$1.662.450	-$1.226	-0.1%
15.000	658	75	$1.593.549	$1.592.324	-$1.226	-0.1%
20.000	2.632	25	$2.496.200	$2.494.565	-$1.634	-0.1%
20.000	1.316	50	$2.215.696	$2.214.061	-$1.634	-0.1%
20.000	877	75	$2.122.123	$2.120.489	-$1.634	-0.1%
25.000	3.289	25	$3.118.133	$3.116.090	-$2.043	-0.1%
25.000	1.645	50	$2.767.716	$2.765.673	-$2.043	-0.1%
25.000	1.096	75	$2.650.697	$2.648.654	-$2.043	-0.1%
30.000	3.947	25	$3.740.279	$3.737.827	-$2.452	-0.1%
30.000	1.974	50	$3.319.736	$3.317.284	-$2.452	-0.1%
30.000	1.316	75	$3.179.484	$3.177.033	-$2.452	-0.1%
35.000	4.605	25	$4.362.425	$4.359.565	-$2.860	-0.1%
35.000	2.303	50	$3.871.756	$3.868.896	-$2.860	-0.1%
35.000	1.535	75	$3.708.058	$3.705.198	-$2.860	-0.1%
40.000	5.263	25	$4.984.571	$4.981.303	-$3.269	-0.1%
40.000	2.632	50	$4.423.777	$4.420.508	-$3.269	-0.1%
40.000	1.754	75	$4.236.632	$4.233.363	-$3.269	-0.1%
50.000	6.579	25	$6.228.864	$6.224.778	-$4.086	-0.1%
50.000	3.289	50	$5.527.604	$5.523.518	-$4.086	-0.1%
50.000	2.193	75	$5.293.992	$5.289.906	-$4.086	-0.1%
60.000	7.895	25	$7.473.156	$7.468.253	-$4.903	-0.1%
60.000	3.947	50	$6.631.644	$6.626.741	-$4.903	-0.1%
60.000	2.632	75	$6.351.353	$6.346.450	-$4.903	-0.1%
70.000	9.211	25	$8.717.448	$8.711.728	-$5.720	-0.1%
70.000	4.605	50	$7.735.685	$7.729.964	-$5.720	-0.1%
70.000	3.070	75	$7.408.501	$7.402.780	-$5.720	-0.1%

Docket No: 10-237
Witness: Howard Solganick
Exhibit: HS-5

Delaware PSC Staff **Exhibit HS-5**

Stability Analysis

	Current Rate Design			Staff Proposed Rate Design		
Rate Element	**Present Revenue**	**Customer Focused Fixed**	**Externally Influenced Volumetric**	**Proposed Revenue**	**Customer Focused Fixed**	**Externally Influenced Volumetric**
	(1)	(2)	(3)	(4)	(5)	(6)
Residential Gas Service Rate Design						
Customer Charge	$ 12,967,700	30.2%		$ 17,456,433	41.0%	
($ per month)						
First 50 CCF Commodity Rate	$ 16,626,653		38.7%	$ -		
Winter Over 50 CCF Commodity Rate	$ 13,406,762		31.2%	$ -		
Design Day Contribution Rate	$ -			$ 25,111,915	59.0%	
($ per CCF of DDC per Year)						
Total	$ 43,001,115	30.2%	69.8%	$ 42,568,348	100.0%	0.0%
General Gas Service Rate Design						
Customer Charge ($ per month)						
GG	$ 3,077,318	17.9%		$ 4,460,754	26.2%	
GVFT	$ 123,342	0.7%		$ 128,352	0.8%	
First 750 CCF Commodity Rate	$ 7,281,446		42.4%	$ -		
Over 750 CCF Commodity Rate	$ 6,710,215		39.0%	$ -		
Design Day Contribution Rate	$ -			$ 12,430,190	73.0%	
($ per CCF of DDC per Month)						
Total	$ 17,192,321	18.6%	81.4%	$ 17,019,295	100.0%	0.0%
Medium Volume Gas (MVG) Service Rate Design						
MVG						
Customer Charge ($ per month)	$ 142,133	4.9%		$ 142,133	4.9%	
Demand MDQ MCF Rate	$ 729,487	25.0%		$ 729,487	25.3%	
Commodity MCF Rate	$ 164,823		5.7%	$ 157,322		5.5%
MVFT						
Customer Charge ($ per month)	$ 270,765	9.3%		$ 270,765	9.4%	
Demand MDQ MCF Rate	$ 1,128,456	38.7%		$ 1,128,456	39.1%	
Commodity MCF Rate	$ 479,887		16.5%	$ 458,047		15.9%
Total	$ 2,915,550	77.9%	22.1%	$ 2,886,209	78.7%	21.3%
Large Volume Gas (LVG) Service Rate Design						
LVG						
Customer Charge ($ per month)	$ 15,230	0.5%		$ 15,230	0.5%	
Demand MDQ MCF Rate	$ 57,500	2.0%		$ 57,500	2.0%	
Commodity MCF Rate	$ 17,141		0.6%	$ 16,012		0.6%
LVFT						
Customer Charge ($ per month)	$ 130,980	4.6%		$ 130,980	4.6%	
Demand MDQ MCF Rate	$ 2,230,804	77.6%		$ 2,230,804	78.4%	
Commodity MCF Rate	$ 421,790		14.7%	$ 394,008		13.9%
Total	$ 2,873,444	84.7%	15.3%	$ 2,844,533	85.6%	14.4%
Gas Lighting Sales Service (GL) Rate Design						
Customer Charge ($ per month)	$ 710	100.0%		$ 703	100.0%	
Total	$ 710	100.0%	0.0%	$ 703	100.0%	0.0%
GRAND TOTAL DELIVERY REVENUE	$ 65,983,141	$ 20,874,425	$ 45,108,715	$ 65,319,088	$ 64,293,700	$ 1,025,388
OVERALL		31.6%	68.4%		98.4%	1.6%

Delaware PSC Staff **Exhibit HS-6**

Penalty Provisions

	Firm Service – Present – Threshold	Firm Service – Present – Incremental Penalty	Firm Service – Proposed – Threshold	Firm Service – Proposed – Incremental Penalty	Interruptible Service – Present – Threshold	Interruptible Service – Present – Incremental Penalty
Delmarva - DE						
Daily MDQ Overrun	10%	per MCF $ 20.00	10%	per MCF $ 50.00		
Post Notification		$ 35.00		$ 60.00		
Chesapeake - DE						
	Balancing none	per Dt (1.035) $ 30.00			Balancing none	per Dt (1.035) $ 30.00
Post Notification					ITS, IBE none	per CCF $ 5.00
Chesapeake -MD						
Unauthorized Overrun	daily	5 times Transco Zone 6 non NY				
	Balancing none	per Dt (1.035) $ 30.00			Balancing none	per Dt (1.035) $ 30.00
Post Notification					IS none	per CCF $ 5.00
PECO						
Daily MDQ Overrun	LHLF none	per MCF $ 25.00				
Daily MDQ Overrun	TCS none	per MCF $ 25.00				
Interrupted Receipts	TS-F none	per MCF $ 25.00			TS-I none	per MCF $ 25.00
Balancing Chanrge	TS-F 10%	per MCF $ 25.00			TS-I 10%	per MCF $ 25.00
PSEG						
Post Notification					TSG-NF, CIG none only one hour requirement	per therm $ 2.02
SJG						
Max Capability Overrun	GSG, GSG-LV, CTS, LVS, EGS monthly average	10 times Transco Zone 6 non NY				
Post Notification	GSG none	10 times Transco Zone 6 non NY			IGS, ITS none	10 times Transco Zone 6 non NY
BG&E						
During Interruption					IS none	per therm $ 1.00

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF	)	
DELMARVA POWER & LIGHT COMPANY FOR	)	
AN INCREASE IN GAS BASE RATES	)	PSC DOCKET NO. 10-237
AND MISCELLANEOUS TARIFF CHANGES	)	
(FILED JULY 2, 2010)	)	

DIRECT TESTIMONY OF

RALPH C. SMITH

ON BEHALF OF

THE COMMISSION STAFF

October 28, 2010

DIRECT TESTIMONY OF RALPH C. SMITH
TABLE OF CONTENTS

Page

Appendices and Exhibits

Appendix A, Qualifications

Appendix B, Supporting Schedules

Appendix C, Data Request Responses and Other Documents Referenced in the Testimony

Appendix D, Excerpts from NARUC-Sponsored Audits of the Expenditures of the American Gas Association and AGA Budget Information

Appendix E, Excerpt from a Florida Public Service Commission Staff Memorandum (dated 12/23/03) in a City Gas Company rate case addressing the AGA dues issue

I. INTRODUCTION

Q. Please state your name and business address.

A. Ralph C. Smith, 15728 Farmington Road, Livonia, Michigan 48154.

Q. What is your occupation?

A. I am a certified public accountant and a senior utility regulatory consultant with Larkin & Associates, PLLC, a firm of certified public accountants and regulatory consultants.

Q. What is your educational background and regulatory experience?

A. Please see Appendix A attached hereto for the details of my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Staff of the Delaware Public Service Commission ("Staff").

Q. Please describe the tasks you performed related to your testimony in this case.

A. Larkin & Associates obtained and reviewed the filings submitted by Delmarva Power & Light Company ("Delmarva," "DPL" or "Company") in this docket relating to the Company's request for (a) an increase in gas delivery base rates; (b) a Volatility Mitigation Rider ("Rider VM"); and (c) a Utility Facility Relocation Charge ("UFRC"). I reviewed Company testimony and responses to data requests served upon DPL by Staff and other parties in this proceeding and performed other procedures as necessary to obtain an understanding of the Company's proposed increase to gas delivery base rates and to formulate an opinion concerning the reasonableness and appropriateness of the Company's adjustments.

Q. What revenue increase has the Company requested?

A. DPL's original '6+6" filing on July 2, 2010 requested an increase of $11.915 million, or 6.3% of total revenues. DPL's "12-+0" filing on September 10, 2010 (the "12+0 Update") requested an increase of approximately $11.556 million, or 6.2% of total revenues. DPL's AMI Supplemental Testimony (the "AMI Supplemental Testimony") filed on October 11, 2010 shows a revenue increase request of $10.204 million, or 5.4% of total revenues.

Q. Which version of DPL's revenue requirement filings did you use as the basis for Staff's revenue requirement?

A. As shown on Exhibit RCS-1 Column A, I used the Company's 12+0 Update.

Q. What issues will you be addressing in your testimony?

A. My direct testimony identifies and discusses areas of concern with respect to DPL's proposed revenue requirement, rate base and net operating income.

My direct testimony also identifies and discusses areas of concern with respect to DPL's proposed accounting deferral of 2009 pension costs and the amount of pension expense that should be allowed for ratemaking purposes.

Finally, I address DPL's proposed Rider VM and Utility Facility Relocation Charge.

Q. Have you prepared any exhibits that are included with your testimony?

A. Yes. Appendix B presents supporting schedules and Appendix C presents responses to data requests and other documents that are referenced in my testimony. These Appendices are attached to my testimony. The supporting schedules were prepared by me or under my supervision and direction.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations.

A. Based on my review of the Company's testimony, on the discovery that has been conducted, on publicly available information, and on my experience in the area of regulatory accounting, policy, and revenue requirement determination, my conclusions and recommendations are as follows:

- The Company has a test period pro forma revenue requirement <u>sufficiency</u> of $664,061, as shown on Schedule RCS-1. This is $12,219,699 lower than the claimed deficiency of $11,555,638 shown in DPL's 12+0 Update. This is also $10,867,887 lower than DPL's revised request of $10,203,826 as presented in the AMI Supplemental Testimony.
- The Company has a test period pro forma rate base of $233,733,292, as shown on Schedule RCS-3.
- The Company has a test period pro forma net operating income of $15,709,575 as shown on Schedule RCS-4.
- Staff's witness James Rothschild has recommended a return on equity of 8.25% to 9.25%, and recommends using 9.25% for DPL, based on his analysis of the market-required return. He recommends an equity cost rate of 8.25% if decoupling provisions are adopted, and an overall cost of capital of 6.55%. I have employed Mr. Rothschild's recommendations to compute DPL's revenue deficiency.

- The Commission should order a detailed review of affiliated charges, including but not limited to the charges from PHI Service Company to DPL outside of the context of a DPL rate case, such that the results of such review would be available for use in DPL's next rate case.
- The Company's request to defer 2009 pension costs for accounting purposes as a regulatory asset should be rejected.
- The Company's related ratemaking proposal for "regulatory asset" treatment of 2009 pension related costs portrayed on Delmarva witness Ziminsky's Schedule JCZ-15 (Adjustment No. 27), which would establish a regulatory asset of $4.090 million amortized over five years (with the unamortized balance included in rates), should be rejected.
- The pension expense requested by the Company for inclusion in rates, based upon 2010, is abnormally high. A normalized allowance for pension expense should be used. For the reasons explained in my testimony, I recommend a normalized allowance for pension expense based on an average of 2008 and 2009. The pension expense included in DPL's 12+0 Update should be reduced from $3,166,916 on a DPL gas distribution-related basis to $1,934,978. The impact is a reduction to the Company's filing of $1,231,938 on a DPL gas distribution-related O&M expense basis.
- The Company's request to implement Rider VM should be rejected.
- The Company's requested UFRC should initially be set at zero.

A summary of the differences between Staff and DPL is presented in the following table:

Description	Appendix B Schedule Reference	Component	Staff Adjustments	Staff Multiplier	Staff Revenue Requirement Amount
			(A)	(B)	(C)
	RCS-5	ROR Difference		-1.4886%	
Rate Base	RCS-2	GRCF		x 1.690134	
Rate Base per DPL's 12+0 Update Filing	RCS-3		$250,588,453	-2.516%	$ (6,304,475)
	RCS-5	Rate of Return		6.55%	
Effect of Staff Adjustments to Rate Base	RCS-2	GRCF		x 1.690134	
			Sch RCS-3		
Pension Regulatory Asset	RCS-6		$ (2,184,341)	11.08%	$ (241,928)
Unamortized Regulatory Commission Expense	RCS-7		$ (333,321)	11.08%	$ (36,917)
Construction Work in Progress	RCS-8		$ (2,446,313)	11.08%	$ (270,942)
Cash Working Capital	RCS-9		$ 74,319	11.08%	$ 8,231
Reverse DPL's AMI Related Pro Forma Adjustments	RCS-10		$ (11,507,547)	11.08%	$ (1,274,523)
AMI Deferred Costs	RCS-11		$ (457,958)	11.08%	$ (50,721)
Total Staff Rate Base Adjustments			$ (16,855,161)		
Staff Adjusted Original Cost Rate Base	RCS-3		$233,733,292		
Net Operating Income		Pre-Tax		Staff	
		Operating Income	NOI Amount	GRCF	
Effect of Staff Adjustments on NOI		Amount	Sch RCS-4	Sch. RCS-2	
Amortization of Pension Regulatory Asset	RCS-12	$ 817,944	$ 485,409	1.690134	$ (820,406)
Normalized Pension Expense	RCS-13	$ 1,231,938	$ 731,093	1.690134	$ (1,235,646)
Regulatory Commission Expense	RCS-14	$ 56,167	$ 33,332	1.690134	$ (56,336)
Wage and Salary Expense	RCS-15	$ 436,448	$ 259,010	1.690134	$ (437,762)
Payroll Tax Expense	RCS-16	$ 33,388	$ 19,814	1.690134	$ (33,488)
Non-Executive Incentive Compensation Expense	RCS-17	$ 935,045	$ 554,903	1.690134	$ (937,860)
Executive Compensation Expense	RCS-18	$ 18,853	$ 11,188	1.690134	$ (18,910)
Stock-Based Compensation Expense	RCS-19	$ 168,630	$ 100,073	1.690134	$ (169,137)
Supplemental Executive Retirement Plan	RCS-20	$ 190,184	$ 112,865	1.690134	$ (190,756)
Allowance For Funds Used During Construction	RCS-21	$ -	$ (13,522)	1.690134	$ 22,854
Interest Synchronization	RCS-22	$ -	$ (339,154)	1.690134	$ 573,216
Membership and Industry Association Dues	RCS-23	$ 45,721	$ 27,133	1.690134	$ (45,858)
Employee Benefits	RCS-24	$ 315,158	$ 187,030	1.690134	$ (316,106)
Reverse DPL's AMI Related Pro Forma Adjustments	RCS-25	$ 195,928	$ 127,777	1.690134	$ (215,961)
AMI Deferred Costs	RCS-26	$ 53,220	$ 31,584	1.690134	$ (53,380)
Gas Decoupling Customer Education Expense	RCS-27	$ 106,500	$ 63,202	1.690134	$ (106,820)
Normalized Meals and Entertainment Expense	RCS-28	$ 12,900	$ 7,656	1.690134	$ (12,939)
Total Staff Adjustments to Operating Income	RCS-4	$ 4,618,024	$ 2,399,393		
Net Operating Income per Company Filing	RCS-4		$ 13,310,182		
Staff Adjusted Net Operating Income	RCS-4		$ 15,709,575		
Gross Revenue Conversion Factor Difference:					
Per Staff	RCS-2			1.690134	
Per Company	RCS-2			1.690134	
Difference				0.000000	
Company Adjusted NOI Deficiency	RCS-1			$6,837,130	
GRCF Difference					$ -
STAFF REVENUE REQUIREMENT ADJUSTMENTS ABOVE					$ (12,226,570)
Company Requested Base Rate Revenue Increase	RCS-1				$ 11,555,638
Reconciled Revenue Requirement					$ (670,932)
Revenue Requirement Calculated on Schedule RCS-1	RCS-1				$ (664,061)
Unidentified Difference (Rounding)					$ (6,871)

III. ORGANIZATION OF SUPPORTING SCHEDULES

Q. How are the supporting schedules in Appendix B organized?

A. They are organized into two groups, summary schedules and adjustment schedules. The adjustment schedules are organized into rate base adjustments and net operating income adjustments. A description of each schedule within Appendix B is identified on the contents page which appears at the front of the appendix. The summary schedules are presented first. Then the schedules showing the derivation of each of the recommended adjustments are presented. The summary schedules are labeled RCS-1 through RCS-5.

The adjustment schedules are labeled RCS-6 through RCS-28. For ease of reference, the adjustment identifier is also shown on the adjustment schedules.

Q. Could you briefly describe what is shown on each of the summary schedules?

A. Yes. Schedule RCS-1 shows the change in the Company's revenue requirement, *i.e.,* the calculation of the revenue increase for utility service. Schedule RCS-1 presents the revenue requirement deficiency or excess that results from Staff's recommended adjustments to operating income and rate base and the application of the rate of return shown on Schedule RCS-5. Put another way, Schedule RCS-1 presents the change in DPL's revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on the proposed rate base.

Q. Please explain the calculation of the revenue requirement shown on Schedule RCS-1.

A. The rate base shown on line 1 of Schedule RCS-1 is the net amount of investment in utility assets associated with the provision of utility service upon which DPL should earn a return. The rate base is multiplied by the rate of return to determine the return requirement, which is sometimes referred to as a net operating income requirement. This is shown on lines 2 and 3 of Schedule RCS-1. The return requirement is then compared with the Company's achieved net operating income, which is sometimes referred to as pro forma adjusted net operating income. Adjusted net operating income is shown on line 4 of Schedule RCS-1. The difference between these two amounts is the net operating income deficiency, which is shown on line 5 of Schedule RCS-1. If DPL was "over-earning" (*i.e.,* earning in excess of the rate of return shown on line 2 of Schedule RCS-1, the amount on line 5 would be a net operating income sufficiency or excess.

Q. Your Appendix B also includes a Schedule RCS-2. What does that schedule show?

A. Schedule RCS-2 shows the calculation of my recommended Gross Revenue Conversion Factor ("GRCF"). The GRCF performs the function of converting amounts from net operating income or return requirement into their equivalent revenue requirement impact. Schedule RCS-2 shows the GRCF of 1.69013 proposed by DPL in column A. This takes into consideration the impact of the PSC assessment, as well as state and federal income taxes.

Q. Please continue with your explanation of the summary schedules.

A. Schedule RCS-3 presents the recommended rate base. Page 2 of this schedule summarizes each of Staff's recommended adjustments to rate base.

Schedule RCS-4 shows the adjusted pro forma net operating income. Pages 2 through 4 of this schedule summarize each of Staff's recommended adjustments to net operating income.

Schedule RCS-5 presents the calculation of cost of capital.

Q. Please explain what is shown on Schedule RCS-5.

A. Lines 1-3 of Schedule RCS-5 present a summary of the cost of capital that DPL is requesting in the current rate case. This information is from DPL's filing at Minimum Filing Requirement ("MFR") Schedule 4.

Lines 4-6 summarize the recommendation of Staff witness James Rothschild concerning the capital structure and cost of capital.

IV. THE COMPANY'S APPLICATION FOR NEW RATES

Q. Please provide a brief background of the Company's request for new rates for gas utility service and the related revenue increase DPL has requested in this case.

A. On July 2, 2010, DPL filed a petition for a gas base rate revenue increase of $11.9 million, or approximately 17.43% over adjusted revenues at current rates, based on a partially-projected test period ending June 30, 2010, using six months actual and six months of projected information. On September 10, 2010, DPL updated its filing to reflect 12 months of actual information through June 30, 2010. This 12+0 Update reflected a gas base rate revenue increase of $11.6 million, or approximately 16.91% over adjusted revenues at current rates. As noted previously, I used the 12+0 Update as the source for the Company's requested rate base and adjusted net operating income. The Staff adjustments that I discuss in my testimony are made to DPL's 12+0 Update.

On October 11, 2010, DPL filed AMI Supplemental Testimony and exhibits to reflect the impact on the Company's requested rate base and adjusted net operating income related to changes in the schedule as a result of delays in its deployment of Advanced Metering Infrastructure ("AMI") devices on gas meters. DPL's AMI Supplemental Testimony reflects the reversal of the Company's adjustments related to AMI, including DPL Adjustment No. 18 for AMI Net O&M Expense, DPL Adjustment No. 19 for AMI Net Plant Additions and Related Expenses, and DPL Adjustment No. 20 for AMI Stranded Costs, as well as revisions to DPL Adjustment No. 21 for AMI Deferred Costs, and certain other adjustments for labor costs, etc., that are impacted by the revised AMI deployment schedule. As demonstrated in the Company's AMI Supplemental Testimony, its requested revenue requirement increase has been reduced to $10.2 million. I have reflected DPL's revised adjustment amounts for DPL Adjustment Nos. 18 through 21 in Staff Adjustments RB-5, RB-6, NOI-14 and NOI-15; however, I continued to use DPL's 12+0 Update as the basis for my adjustments. I also discuss each of DPL's other AMI-related revisions in the context of the adjustments I am recommending to the rate base and net operating income and expense amounts contained in DPL's 12+0 Update.

V. ANALYSIS AND DISCUSSION

Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is organized around issue discussions. Each adjustment to rate base and net operating income that I and other Staff witnesses recommend is discussed in a separate section of the testimony.

Rate Base Adjustments

RB-1, Pension Regulatory Asset

Q. Please explain Staff Adjustment RB-1.

A. Staff Adjustment RB-1 removes from rate base the $3,680,750 Pension Regulatory Asset that DPL requested relating to deferral and recovery of its abnormally high 2009 pension cost. See Schedule RCS-6. Net of a related impact on Accumulated Deferred Income Tax ("ADIT") of $1,496,409, this adjustment reduces DPL's proposed rate base by $2,184,341.

Q. Please discuss DPL's request to defer 2009 pension costs for accounting purposes.

A. On May 1, 2009, DPL filed a request for authorization to defer "excess" pension costs from the Company's financial statements as a result of "the effect of recent economic developments on pension assets."

In Docket No. 09-182, DPL submitted testimony in support of its request from Anthony Kamerick, Senior Vice President and Chief Financial Officer of Pepco Holdings, Inc. ("PHI") and Delmarva. DPL sought to establish a regulatory asset for an alleged shortfall between Delmarva's actual 2009 pension expense and the amount of pension income included in Delmarva's current distribution rates.

On January 13, 2010, in Docket No. 09-182, DPL filed Supplemental Direct Testimony on this issue from Jay Ziminsky, Manager of Revenue Requirements in the Regulatory Affairs Department of PHI.

In Order No. 7727 in Docket No. 09-414, the Company's electric base rate case, the Commission consolidated Docket No. 09-182 into the electric base rate case insofar as the electric portion of the issue was concerned, and ordered that the gas portion of the issue be considered in Delmarva's next general gas base rate case. In the current DPL gas rate case, the Company's request for a regulatory asset related to 2009 pension cost is addressed in DPL witness Ziminsky's direct testimony at pages 12-16.

Q. What amounts for pension cost has the Company sought to defer?

A. The Company requests deferral of $4.090 million of Delaware Gas pension costs by establishing a regulatory asset in that amount. This amount is based on the difference between (1) the actuarially determined 2009 pension expense, which Mr. Ziminsky calculates to be $3,912,379 and (2) the ($177,343) of pension income that he calculates was inherently included in the rates resulting from DPL's last gas rate case, Docket No. 06-284.[1] The amounts include both DPL pension costs and PHI Service Company pension costs that are charged to DPL.

Q. What reasons does the Company provide for its requested ratemaking treatment?

A. The Company cites the following reasons:[2]

- The Delaware Gas pension expense dramatically increased in 2009 as a direct result of adverse overall economic conditions.

[1] Brackets indicate net pension income, i.e., negative pension expense.
[2] Ziminsky Direct at page 14.

- The increase was out of the Company's control.
- Pension expense should be viewed similar to storm damages.

Q. What is DPL specifically requesting for the 2009 pension "regulatory asset" for ratemaking purposes?

A. As shown on Mr. Ziminsky's Schedule JCZ-15 (Adjustment No. 27), the Company is requesting amortization of the 2009 pension "regulatory asset" of $4.090 million over five years, for an annual pre-tax expense operating increase of $817,944, and that the "Year 1" unamortized balance of $3.681 million be included in rate base, net of related ADIT, for a net rate base increase of $2.184 million.

Q. Have DPL and its affiliate PEPCO sought similar "regulatory asset" treatment relating to 2009 pension costs in Maryland and the District of Columbia?

A. Yes.

Q. How did the Maryland Commission address Delmarva's request to defer and amortize pension expense in Delmarva's then-pending Maryland rate case?

A. In Order No. 83085 (dated December 30. 2009) in Case No. 9192, the Maryland Commission rejected Delmarva's proposal to defer and amortize pension expense, finding that it represented single-issue ratemaking. At pages 15-16 of that order, the Maryland Commission stated:

> We rejected similar proposals in Delmarva's last rate case because surcharges guarantee dollar-for-dollar recovery of specific costs, diminish the Company's incentive to control those costs, and exclude classic, ongoing utility expenses from the standard, contextual ratemaking analysis. We found before that tracker mechanisms, like the surcharge and

> amortization proposals in this case, represent an extraordinary form of ratemaking that we reserve only for very large, non-recurring expense items that have the potential to seriously impair a utility's financial well-being and that do not contribute to the Company's rate base. Pension and OPEB expenses fail this test, even in a bad year – they are classic, ongoing costs of running a utility company, and cannot, in our view, qualify for specialized rate treatment. We find again, as we did in 2007, that a pension and OPEB surcharge breaches the historical ratemaking bargain, and the economic challenges of the last two years offer no reason for us to jettison these long-settled principles. We therefore reject the Company's surcharge and amortization proposals and direct it to continue recovering these expenses through rates.
>
> (footnotes omitted).

Q. How did the District of Columbia Commission decide this issue?

A. The District of Columbia Commission similarly rejected Pepco's requested treatment in Formal Case No. 1076, stating as follows:

> The Commission rejects Pepco's alternative proposal seeking the creation of a 'regulatory asset' for recovery of its pension costs. … It also accords with the recent decision of the Maryland Public Service Commission, which rejected a similar request by Delmarva Power & Light for a surcharge, or amortization, of large pension and OPEB costs incurred because of the recent economic downturn. None of the other jurisdictions to which Pepco has applied … has authorized Pepco to treat its 2009 pension expense as a regulatory asset.
>
> ...Traditional ratemaking analysis is well-suited to address fluctuations I pension costs. Pepco did not demonstrate that its financial situation is as precarious, or that its pension fund losses were as extreme. … Regulatory asset treatment might diminish Pepco's incentives to control its pension costs. … The Commission finds that, on this record, Pepco failed to carry its burden of proof to justify a departure from traditional ratemaking procedures for recurring pension costs.
>
> (footnotes omitted)

Q. What is Staff's recommendation concerning the Company's request for regulatory asset treatment of pension expense?

A. Its proposal is the equivalent of piecemeal ratemaking and should be rejected. The Company has never had an automatic deferral mechanism for pension expense, and it has not demonstrated that pension expense requires special ratemaking treatment now. Pension expense should be addressed in this rate case - as in all rate cases - as an O&M expense. There is no need for establishing a regulatory asset for future recovery of 2009 pension expense. The reason that commissions authorize a return on equity for utilities is because shareholders bear the risk, among other things, that operating expenses may fluctuate from year to year. Granting the Company's requested ratemaking treatment would eliminate that risk with no corresponding reduction in the cost of equity, to the detriment of the ratepayers. Furthermore, I am advised by counsel that DPL's regulatory asset treatment of a past expense for deferral and future recovery is also objectionable on retroactive ratemaking grounds. See, e.g., the legal arguments presented in Staff's briefs in Docket No. 09-414 et al. As explained in those Staff legal briefs, this is retroactive ratemaking because DPL is requesting specific future recovery of a past expense.

Q. Could the adoption of DPL's proposed regulatory asset treatment for its 2009 pension costs provide a disincentive for making just and reasonable reforms to the Company's pension plans?

A. I believe that it could. Factors such as worker mobility, the ERISA and other compliance and reporting requirements, and the increased costs of defined benefit pension plans have hastened their decline, and there is a discernible trend away from such plans. Providing what essentially would amount to a guaranteed recovery of the abnormally high 2009 pension expense recovery could deter the Company from making reforms to its pension plans that would reduce cost, as many companies are doing.

Q. What evidence do you have that indicates a trend away from defined benefit plans?

A. In March 2009, the U.S. Government Accountability Office issued a report (GAO-09-291, dated March 30, 2009),[3] which concluded that:

> **The number of private defined benefit (DB) pension plans,** an important source of retirement income for millions of Americans, **has declined substantially over the past two decades. For example, about 92,000 single-employer DB plans existed in 1990, compared to just under 29,000 single-employer plans today.** Although this decline has been concentrated among smaller plans, **there is a widespread concern that large DB plans covering many participants have modified, reduced, or otherwise frozen plan benefits in recent years.** GAO was asked to examine (1) what changes employers have made to their pension and benefit offerings, including to their defined contribution (DC) plans and health offerings over the last 10 years or so, and (2) what changes employers might make with respect to their pensions in the future, and how these changes might be influenced by changes in pension law and other factors. To gather information about overall changes in pension and health benefit offerings, GAO asked 94 of the nation's largest DB plan sponsors to participate in a survey; 44 of these sponsors responded. These respondents represent about one-quarter of the total liabilities in the nation's single-employer insured DB plan system as of 2004. The survey was largely completed prior to the current financial market difficulties of late 2008.
>
> GAO's survey of the largest sponsors of DB pension plans revealed that **respondents have made a number of revisions to their retirement benefit offerings over the last 10 years or so. Generally speaking, they have changed benefit formulas; converted to hybrid plans (such plans are legally DB plans, but they contain certain features that resemble DC plans); or frozen some of their plans.** Eighty-one percent of responding sponsors reported that they modified the formula for computing benefits for one or more of their DB plans. Among all plans reported by respondents, 28 percent of these (or 47 of 169) plans were under a plan freeze--an amendment to the plan to limit some or all future pension accruals for some or all plan participants. The vast majority of respondents (90 percent, or 38 of 42 respondents) reported on their 401(k)-

[3] A copy of the complete GAO study can be obtained online at: http://www.gao.gov/new.items/d09291.pdf

type DC plans. Regarding these DC plans, a majority of respondents reported either an increase or no change to the employer or employee contribution rates, with roughly equal responses to both categories. About 67 percent of (or 28 of 42) responding firms plan to implement or have already implemented an automatic enrollment feature to one or more of their DC plans. With respect to health care offerings, all of the (42) responding firms offered health care to their current workers. Eighty percent (or 33 of 41 respondents) offered a retiree health care plan to at least some current workers, although 20 percent of (or 8 of 41) respondents reported that retiree health benefits were to be fully paid by retirees. Further, 46 percent of (or 19 of 41) responding firms reported that it is no longer offered to employees hired after a certain date. At the time of the survey, most sponsors reported no plans to revise plan formulas, freeze or terminate plans, or convert to hybrid plans before 2012. When asked about the influence of recent legislation or changes to the rules for pension accounting and reporting, responding firms generally indicated these were not significant factors in their benefit decisions. Finally, a minority of sponsors said they would consider forming a new DB plan. Those sponsors that would consider forming a new plan might do so if there were reduced unpredictability or volatility in DB plan funding requirements and greater scope in accounting for DB plans on corporate balance sheets. **The survey results suggest that the long-time stability of larger DB plans is now vulnerable to the broader trends of eroding retirement security. The current market turmoil appears likely to exacerbate this trend.**

I am also aware that the following utilities have closed, frozen, significantly modified or discontinued their defined benefit pension plans:

- PacifiCorp / Rocky Mountain Power – In 2007, the company froze the final average pay formula for non-union employees and will make future accruals under a cash balance formula. Employees hired on or after 1/1/08 do not participate in the retirement plan. In 2008 the company (1) froze the final average pay formula within the retirement plans and ceased future accruals for Local 659 union employees and Local S1978 union employees; and (2) froze the final average pay formula within the retirement plan and ceased future accruals for Local 125 union employees hired prior to 1/1/06 and over a certain age. Effective 1/1/09, non-union employees were permitted to choose to continue receiving pay credits under the cash balance formula approach within the retirement plan or to receive the credits as additional fixed contribution within the 401(k) plan during a limited election period.
- American Water Works Company, Inc. – The company closed the defined benefit pension plan to all non-union employees hired on or after 1/1/06, and froze the

accrued benefits under the defined benefit plan for union employees hired on or after 1/1/01.

- Aqua America, Inc. – Employees hired after April 1, 2003 do not participate in the Company's defined benefit pension plans.
- Verizon – As of 6/30/06, Verizon management employees no longer earn pension benefits under the defined benefit plan.
- Shenandoah Telecommunications Company – The defined benefit pension plan was frozen as of 1/31/07; the company also announced its intent to settle benefits earned under the plan and terminate the plan.
- Cincinnati Bell – Effective 3/28/09, the company froze pay-related pension credits under the defined benefit pension plan for managers and non-union employees who were accruing benefits under such plan, were under the age of 50, and were not eligible for the 2007 early retirement option.

Additionally, United Illuminating Company, Vermont Electric Cooperative (union employees), Connecticut Natural Gas, Southern Connecticut Gas, and Northeast Utilities no longer offer defined benefit pension plans to new hires or only allow for the cash balance plan for new hires.

Additionally, see Appendix C for the following other related articles and studies:

- Excerpt from Waters Corporation's September 4, 2007 Form 8-K.
- Dow Jones Newswire article – "Pension-Plan Freezes Likely to Ramp Up Next Year" (By Lynn Cowan, March 20, 2009).
- Pension Rights Center: Pension Publications listing – Companies That Have Changed Their Defined Benefit Pension Plans (As of April 2, 2009).
- GAO Defined Benefit Pensions – Plan Freezes Affect Millions of Participants and May Pose Retirement Income Challenges (A copy of the complete GAO report can be obtained online at: http://www.gao.gov/new.items/d08817.pdf).
- GAO Defined Benefit Pensions: Survey of Sponsors of Large Defined Benefit Pension Plans (July 2008).
- Deloitte 2008 Survey of Economic Assumptions.

Q. Please summarize your recommendation concerning DPL's proposal to create a "regulatory asset" for 2009 pension costs.

A. DPL's proposed "regulatory asset" treatment for 2009 pension expense should be denied because:

- it constitutes retroactive ratemaking,
- it violates the traditional ratemaking treatment afforded these expenses,
- it inappropriately shifts risk of fluctuating pension costs between rate cases away from shareholders and onto ratepayers, without any benefit to ratepayers in the form of a reduction to the cost of equity,
- it reduces incentives to modify the pension plan to reduce cost,
- it results in rates that are based on an abnormally high expense level, and
- pension expense is somewhat under the Company's control via the plan design and management's funding decisions.

RB-2, Unamortized Regulatory Commission Expense

Q. Please explain Staff Adjustment RB-2.

A. Staff Adjustment RB-2 removes from rate base $561,667 of unamortized rate case expense. The Company should not be allowed to earn a return on rate case expense. Rate case expense is an operating expense that is typically normalized for ratemaking purposes, and indeed this Commission's longstanding practice has been to normalize rate case expense. Similar to other normalized O&M expenses, no return is provided. Net of a related impact on ADIT of $228,346, this adjustment reduces DPL's proposed rate base by $333,321, as shown on Schedule RCS-7.

RB-3, Construction Work in Progress ("CWIP")

Q. Did the Company include CWIP in its adjusted test period rate base?

A. Yes. Notwithstanding the Commission's disallowance of CWIP in Docket No. 05-304, DPL has included a 13-month average amount of CWIP in its rate base claim in the instant proceeding. As shown on MFR Schedule WMV-1 from DPL's 12+0 Update, the Company included CWIP totaling $4,697,990 in its test period rate base before pro forma adjustments. Although Company witness Von Steuben acknowledged that CWIP was disallowed by the Commission in Docket No. 05-304, he also noted the Commission's statement that the Commission had discretion, based on the facts presented in each individual case, as to whether to include CWIP in rate base.[4]

Q. How was DPL's request for CWIP inclusion in rate base handled in the recent DPL electric rate case?

A. While a final decision has not been issued yet in DPL's most recent electric rate case, Docket No. 09-414 et al, the Hearing Examiner's recommended decision removed CWIP from rate base (and removed related AFUDC from adjusted net operating income), stating as follows on pages 102-103:

> In reaching a decision on this issue, I reviewed the Hearing Examiner's reports in PSC Dockets 05-304 and 91-20. Essentially, Delmarva's argument is that even though this plant is not booked as plant-in-service, it should be deemed to be "used and useful" because it is being employed to provide service to customers. However, the Company wants this Commission to ignore that the plant is booked in a CWIP account. The Company urges the Commission to treat this plant as if it were "plant-in-service" because it has the engineering designation of "technically complete." I must agree with the DPA that the Company has failed to demonstrate which projects are "used and useful" in the provision of service to customers. Without such a showing, it does not appear that the Company has carried its burden of proof on this issue. I understand the lag between the engineering designation of a project that is "technically complete" and when the costs for the project are actually transferred into plant in service, but this lag still does not overcome the fact that the Company did not include in its filing an explanation of which projects were providing service to customers and which were not.

[4] Von Steuben Direct Testimony at 6.

> Further, as noted by the Hearing Examiner in PSC Docket No. 05-304, there is only minimal AFUDC to offset the $13.3 million of CWIP. In this case, the amount of AFUDC creates an effective rate of approximately 0.2%, which is far less that the rate of return requested by the Company. Consequently, including CWIP in rate base in this case creates a significant detrimental impact on revenue requirement, which is the same effect it would have had in PSC Docket No. 05-304 had the Commission allowed it. For these reasons, I recommend to the Commission that it decline the Company's request to include CWIP in rate base.

Q. What did Mr. Von Steuben indicate about test period CWIP that had been closed to plant in service in the current DPL gas rate case?

A. On page 7 of his direct testimony, Mr. Von Steuben stated that of $2,556,979 of gas-specific CWIP on the Company's books as of December 31, 2009 (test year), $1,593,597 had been closed to plant in service as of May 31, 2010. In addition, Mr. Von Steuben stated that the remaining $963,382 ($2,556,979 - $1,593,597) had not yet been closed to plant in service, but that the Company would provide an update related to whether this remaining amount of CWIP was closed to plant in service.[5]

Q. Does the Company's 12+0 Update indicate that the remaining $963,382 of test year CWIP has been closed to plant in service?

A. No. However, DPL's response to data request PSC-LA-172 stated that of the $963,382, $277,123 had not been closed to plant in service as of August 31, 2010, and that if the balance has not been placed into service, then it remains in CWIP. The table below summarizes the gas specific CWIP that was closed to Plant in Service through August 31, 2010 as discussed in Mr. Von Steuben's direct testimony and in the response to PSC-LA-172.

[5] This is also discussed in the direct testimony of Company witness Philip L. Phillips, Jr. at page 6.

Description	Amount
Gas Specific CWIP per DPL's Books at December 31, 2009*	$ 2,556,979
Gas Specific CWIP Closed to Plant in Service as of May 31, 2010	$ (1,593,597)
Remaining 12/31/09 Gas Specific CWIP as of May 31, 2010	$ 963,382
Additional Gas Specific CWIP Placed into Plant in Service during June 2010	$ (373,978)
Remaining 12/31/09 Gas Specific CWIP as of June 30, 2010	$ 589,404
Additional Gas Specific CWIP Placed into Plant in Service during July and August 2010	$ (312,281)
Remaining 12/31/09 Gas Specific CWIP as of August 31, 2010	$ 277,123

* This amount and the adjustments that follow relate only to gas specific CWIP on DPL's books at December 31, 2009

Q. Does that mean that the Company's remaining overall CWIP balance was only $277,123 after the adjustments to Plant in Service shown in the table above?

A. No. As Mr. Von Steuben stated in his direct testimony, the $2,556,979 from which the adjustments to Plant in Service were made pertained only to gas-specific CWIP on the Company's books as of December 31, 2009. The Company's rate case claim for CWIP is based upon a 13-month average for the period ending June 30, 2010, plus or minus pro forma adjustments.

Q. What was the Company's actual CWIP balance at June 30, 2010, the end of the test period?

A. The Company's actual CWIP balance at June 30, 2010 was $5,432,422. This is reflected on Workpaper No. 7 from the Company's 12+0 Update. This workpaper shows the monthly CWIP balances from which the 13-month average of $4,697,990 included in DPL's 12+0 Update was calculated.

Q. How much of the June 30, 2010 CWIP balance of $5,432,422 is designated as Gas-specific CWIP?

A. The Gas-specific CWIP portion of the $5,432,422 is $3,724,538. That is $1,167,559 more than the $2,556,979 of Gas-specific CWIP that Mr. Von Steuben discussed in his direct testimony. In addition, the portion of Gas-specific CWIP included in the 13-month average amount of $4,697,990 is $3,312,697, or $755,718 more than the $2,556,979 recorded on DPL's books at December 31, 2009 that was the focus of Mr. Von Steuben's discussion.

Q. How does the Company's 12+0 Update reflect Company pro forma adjustments to the updated $4,697,990 13-month average test period overall CWIP balance?

A. As shown in the table below, the Company proposed two pro forma adjustments to the $4,697,990 13-month average test period overall CWIP balance in its 12+0 Update. The first such adjustment, reflected on Schedule WMV-12 (Adjustment No. 16), relates to July 2009 through June 2010 actual reliability plant closings. As part of this adjustment, DPL removed CWIP in the amount of $2,251,677.

The second adjustment, reflected on Schedule JCZ-7 (Adjustment No. 19), relates to AMI net plant additions. As part of this adjustment, DPL removed CWIP in the amount of $249,833. After reflecting these two adjustments, the Company's updated adjusted test period CWIP in its 12+0 Update totaled $2,196,480 ($4,697,990 - $2,251,677 - $249,833).

Description	Test Period Average Balance	DPL Adj. No. 16 Test Period Reliability Closings	DPL Adj. No. 19 AMI Net Plant Additions (Removed)	Pro Forma Adjusted CWIP
CWIP - Per 12+0 Update Filing	$ 4,697,990	$ (2,251,677)	$ (249,833)	$ 2,196,480

Q. What is the result of DPL removing Company Adjustment No. 19 on the CWIP amount DPL is requesting to be included in rate base?

A. Company Adjustment No. 19 was removed pursuant to the AMI Supplemental Testimony. As a result of removing that adjustment, the $249,833 of CWIP related to AMI net plant additions was "added back" to the test period CWIP balance.

Q. After reflecting the Company's removal of its AMI-related adjustment, what amount of CWIP has the Company requested?

A. As shown in the table below, after adding back the $249,833 of CWIP per the Company's October 11, 2010 AMI supplemental testimony, DPL's requested CWIP balance is $2,446,313 (2,196,480 + $249,833). The $2,446,313 of CWIP is comprised of Gas-Specific, Service Company, Common and Other CWIP.

Description	Test Period Average Balance	DPL Adj. No. 16 Test Period Reliability Closings	DPL Adj. No. 19 AMI Net Plant Additions (Removed)	Pro Forma Adjusted CWIP
CWIP - Per AMI Filing	$ 4,697,990	$ (2,251,677)	$ -	$ 2,446,313

Q. Should any amount of CWIP be included in adjusted test period rate base?

A. No. All CWIP should be removed from DPL's adjusted rate base because the situation here is similar to the one addressed in Docket No. 05-304, Order No. 6930, DPL's last decided rate case, where the inclusion of CWIP in rate base was disallowed. This situation is also similar to the one addressed in DPL's most recent electric distribution case in the Findings and Recommendations of the Hearing Examiner in Docket No. 09-

414, where CWIP was removed from rate base in the Hearing Examiner's Report. The circumstances that led to the Commission's decision in Docket No. 05-304 and the Hearing Examiner's recommendation in Docket No. 09-414 are similar to the facts of this proceeding.

CWIP, by definition, is not used and useful in the provision of utility service. Additionally, the amount of AFUDC reflected in DPL's adjusted filing is insufficient to offset the return requirement that would be generated by including CWIP in rate base.

Q. Given that the Company's request for CWIP in rate base is based upon a 13-month average through June 30, 2010 (as are other major rate base components, such as Plant in Service), as the starting point, is Mr. Von Steuben's focus on how much of the December 31, 2009 Gas-specific CWIP balance has been placed into service particularly helpful or relevant to evaluating whether a remaining amount of CWIP should be included in rate base?

A. No. The Company's argument for including CWIP in rate base appears to be predicated on it closing some of its December 31, 2009 Gas-specific CWIP balance to Plant in Service as discussed by Mr. Von Steuben and Mr. Phillips in their direct testimonies. This is not particularly relevant or helpful because the Company used a 13-month average balance for most rate base items. What happened to CWIP between December 31, 2009 and June 30, 2010 is only relevant in the overall context of the test year. The Company indicated that $2,279,856 of December 31, 2009 Gas-specific CWIP had been closed to plant in service as of August 31, 2010.[6] However, the $2,279,856 only addresses the Company's gas-specific CWIP balance as of December 31, 2009, not the June 30, 2010 overall CWIP balance of $5,432,422 or the 13-month average test period overall CWIP balance of $4,697,990. The Company has not demonstrated that any of the CWIP it is proposing for inclusion in rate base is used and useful in the provision of service to ratepayers.

Q. Did the Company also reflect an Allowance For Funds Used During Construction ("AFUDC") in its 12+0 Update?

A. As shown on Schedule WMV-1 from the Company's 12+0 Update, DPL included in other operating revenue an adjusted AFUDC amount of $66,307. After reflecting two pro forma adjustments, one related to Company Adjustment No. 16 (reliability plant closings) in the amount of $52,785 and the other related to Company Adjustment No. 19 (AMI net plant additions) in the amount of $11,504), the Company reflected pro forma AFUDC in the amount of $2,018. The Company's AMI Supplemental Testimony removed Company Adjustment No. 19.[7] The $11,504 of AFUDC related to AMI net plant additions was "added back" to the test period AFUDC balance. After adding back the $11,504, DPL's pro forma AFUDC balance is $13,522 ($2,018 + $11,504).

Q. How does the AFUDC balance proposed by DPL relate to your recommendation to remove CWIP from rate base?

[6] This $2,279,856 reflects the $1,593,597 discussed in Mr. Von Steuben's direct testimony at page 7 and the $686,259 of CWIP which the Company stated was closed to plant in service as of August 31, 2010 per PSC-LA-172.

[7] I address the Company's AMI related adjustments in a subsequent section of my testimony.

A. This AFUDC offset is minimal compared to the CWIP balance that DPL proposes to include in rate base. The AFUDC only equates to 0.6 percent of DPL's requested inclusion of CWIP in rate base ($13,522 / $2,446,313). This is considerably less than the 8.04 percent overall rate of return that DPL proposed in its 12+0 Update in this proceeding, and also less than the 6.55% overall rate of return that Staff has recommended. Because the AFUDC allowance is so low in comparison with DPL's CWIP request, including CWIP in rate base contributes to the rate increase and, if not removed, would have a detrimental impact on the Company's ratepayers.

Q. Please explain Staff Adjustment RB-3.

A. As shown on Schedule RCS-8, Staff Adjustment RB-3 removes the $2,446,313 of CWIP that DPL included in its adjusted test period rate base. This amount reflects the Company's total adjusted 13-month average CWIP from its 12+0 Update of $2,196,480 plus the "adding back" of CWIP in the amount of $249,833 that is related to Company Adjustment No. 19, which the Company removed as discussed in the supplemental testimony of Company witness Ziminsky (see additional discussion below) As discussed later in my testimony, with respect to Staff Adjustment NOI-10, I have also removed the corresponding AFUDC in the amount of $13,522 from net operating income..

RB-4, Cash Working Capital ("CWC")

Q. Please explain Staff Adjustment RB-4.

A. Staff Adjustment RB-4 adjusts DPL's requested allowance for CWC.

Q. What is CWC?

A. CWC is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide CWC. In that situation, a positive CWC requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, then ratepayers provide the CWC to the utility, and the negative CWC allowance is reflected as a reduction to rate base. In this case, the CWC requirement is an increase to rate base as investors are essentially supplying these funds.

Q. Does DPL have a positive or negative CWC requirement?

A. DPL has a positive CWC requirement. In other words, the Company is supplying the funds used for the day-to-day operations of the Company prior to when the related revenues are received from ratepayers.

Q. Did DPL present a lead/lag study in support of its CWC requirement?

A. Yes, DPL performed a lead/lag study to calculate the CWC requirement in this case. The Company provided its lead/lag study calculations with the work papers provided in the case.

Q. Are you recommending any revisions to DPL's CWC request?

A. Yes. I have reflected the impact of Staff's adjustments to operating expenses. I have also synchronized the calculation of CWC with Staff's recommended revenue increase.

Q. What is the result of your CWC calculation?

A. As shown on Schedule RCS-9, DPL's filed CWC request should be increased by $74,319.

RB-5, AMI Rate Base Revisions (DPL Adjustments 18 through 20)

Q. Please explain Staff Adjustment RB-4.

A. As shown on Schedule RCS-10, this adjustment reflects the removal of DPL's pro forma rate base increase from Company adjustments 19 and 20 based on DPL's AMI Supplemental Testimony. The reduction to rate base expenses related to DPL's revision of those Company-proposed adjustments is shown in detail on Schedule RCS-10 and is summarized in the following table:

Company Revision to Pre-Tax AMI-Related Rate Base Components

DPL Adj. No.	Description	Per DPL12+0 Filing	Per DPL10-11-2010 AMI Update Filing	DPL Revision (Decrease) Increase
		(A)	(B)	(C)
19	AMI Net Plant Additions		$ -	
	Plant in Service	$ 12,546,785	$ -	$(12,546,785)
	Accumulated Depreciation	$ (458,883)	$ -	$ 458,883
	CWIP	$ (249,833)	$ -	$ 249,833
	Accumulated Deferred Income Taxes	$ (220,763)	$ -	$ 220,763
20	AMI Stranded Costs			
	Plant in Service	$ (4,752,885)	$ -	$ 4,752,885
	Accumulated Depreciation	$ 1,351,353		$ (1,351,353)
	Accumulated Deferred Income Taxes	$ 75,192	$ -	$ (75,192)
	Amortizable Balance	$ 3,216,581	$ -	$ (3,216,581)
	Totals	$ 11,617,306	$ -	$(11,507,547)
	Net Reduction to Rate Base			$(11,507,547)

Source
Col.A DPL 12+0 Update, Schedules
Col.B DPL's 10-11-2010 AMI Supplemental Filing, Schedules JCZ-6 through JCZ-9 AMI Supplemental

RB-6, AMI Deferred Costs

Q. Please explain Staff Adjustment RB-6.

A. Similar to Staff Adjustment RB-5, this adjustment reflects the Company's revision to Adjustment No. 21 pursuant to the AMI Supplemental Testimony. The Company's deferred AMI cost adjustment reflects a similar uncontested adjustment made by DPL in the Company's pending Delaware electric base rate case in Docket No. 09-414. As shown on Schedule RCS-11, the difference between the Company's revised Adjustment No. 21 and that included with its 12+0 update filing results in a $771,688 reduction to amortizable balances with a corresponding ADIT adjustment of $313,730. The net result of these adjustments is an overall net reduction of $457,958 to rate base.

<u>Summary of Adjusted Rate Base</u>

Q. What rate base do you show for DPL after making Staff's recommended adjustments?

A. As shown on Schedule RCS-3, after Staff's recommended adjustments, the rate base for DPL's gas distribution operations is $233,733,292.

<u>Adjustments to Net Operating Income</u>

NOI-1, Amortization of Pension Regulatory Asset

Q. Please explain Staff Adjustment NOI-1.

A. This adjustment removes DPL's requested amortization of a Pension Regulatory Asset. As described above, in conjunction with Staff Adjustment RB-1, DPL's request for approval of a Regulatory Asset for its abnormally high 2009 pension cost should be rejected. Consistent with that recommendation, DPL's requested amortization of a

Pension Regulatory Asset should be removed from operating expenses. Therefore, as shown on Schedule RCS-12, the removal of the Company's proposed amortization of the pension asset reduces amortization expense by $817,944.

NOI-2, Normalized Pension Expense for Ratemaking Purposes

Q. What amount is DPL requesting for pension expense for ratemaking purposes?

A. As shown on Company Adjustment No. 11, DPL is requesting pension expense for ratemaking purposes for its Delaware gas distribution operations of $3,166,916 based on the estimates contained in the 2010 Actuarial Valuation Report (dated August 31, 2010 prepared by its actuary Towers Watson. A copy of this actuarial report was provided in response to data request DPA-25.

Q. Is DPL's proposed pension expense representative of normal ongoing conditions?

A. No. The pension expense appears to be abnormally high. Defined benefit pension plan costs for many companies, not only DPL and its affiliates, were higher than normal starting in 2009 because of the poor investment returns that occurred in the wake of the worldwide financial crisis that began in 2008.

Q. Is the level of pension expense requested by DPL for inclusion in determining the revenue requirement just and reasonable?

A. Based on my review, the level of pension expense in DPL's proposed revenue requirement is not just and reasonable. Rather, it is abnormally high. Moreover, it is not reflective of the pension expense that has typically been recorded in prior years and could considerably overstate pension expense to be incurred during the rate effective period.

Q. Has the Company supplied historical information on DPL's total pension cost?

A. Yes. DPL had net pension income in each year 1999 through 2008, with 2009 being the first year in which DPL had a net periodic pension expense. The 2009 and 2010 results are abnormal in comparison with the prior history. In response to data request DPA-28, the Company provided DPL's total pension costs (or pension income), inclusive of gas and electric amounts that were capitalized and expensed for each year 1999-2010, which is summarized below:

Year	Total DPL Pension (Income) Expense ($000's)	
1999	$	(31,663)
2000	$	(43,839)
2001	$	(18,618)
2002	$	(10,248)
2003	$	(2,634)
2004	$	(9,256)
2005	$	(8,531)
2006	$	(6,580)
2007	$	(6,179)
2008	$	(6,033)
2009	$	13,438
2010	$	18,199

As can be seen from this information, 2009 and 2010 were the only years in which DPL recorded a net positive pension cost in this entire 12-year period.

Q. You indicate that the pension expense in DPL's proposed revenue requirement is not just and reasonable and likely not reflective of the costs that will be incurred in the rate effective period. Please explain.

A. In its filing, DPL has requested for ratemaking purposes an allowance for pension expense based on the 2010 actuarial estimates allocated to Delaware gas distribution operations. This amount is inclusive of DPL's own pension costs and PHI Service Company costs allocated to DPL. As noted above, the pension cost included in the filing was based on estimates provided in the August 31, 2010 actuarial valuation report prepared by Towers Watson. As described above, the amount of pension cost DPL recorded in 2009 and in 2010 to date is abnormally high in comparison to the amounts recorded in each year from 1999 through 2008. DPL had recorded pension income, not a net pension expense, in each of those prior years. At this point, it is likely that the pension expense incurred by DPL during the rate effective period, or beginning in January 1, 2011, will be lower than the projected 2010 costs included in the filing.

Q. Please discuss DPL's historical pension funding and how plan funding and asset levels affect pension cost.

A. Typically, all other things being equal, the better funded a pension plan is, the lower the pension expense. This is because the larger expected return on plan assets serves to offset pension expense in the pension expense equation. Additionally, the funding of pension plan assets serves to reduce future pension costs for many years.

During the 2006-2008 period, DPL made no (i.e., $0) cash contributions to its pension plan assets. In 2009, DPL contributed $10 million to the pension plan fund assets. The Towers Watson report indicated that the total contributions in 2010 on a total PHI basis will be $100 million. The impact of these cash contributions on the pension expense actuarial calculations will not be fully realized during 2010 because the contributions occurred during 2010. By the time the 2011 actuarial calculations are performed, the full impact of the 2010 contributions on the pension expense calculations will be incorporated.

Q. Has DPL provided additional information regarding its projected pension costs for years beyond 2010?

A. No. In response to data request PSC-LA-111, the Company stated in part that it had just received the 2010 actual expense reports for pension and that future projections depend on year-end discount rate and asset return. Therefore, DPL does not have pension projections beyond 2010 at this time.

Q. What is your recommendation for setting the level of pension expense to be included in rates?

A. I recommend that the pension expense to be included in rates on a going-forward basis be determined based on the average of the actual 2008 pension expense[8] and the 2009 pension expense as allocated to DPL's Delaware gas distribution operating and maintenance expense. Using an average of the 2008 and 2009 pension expense would result in a reasonable allowance for pension expense. The purpose of normalization is to determine a "normal" level of expenses that are volatile, such as pension expense that has been due to the abnormal market conditions in late 2008 and early 2009.

[8] The amount of 2008 pension expense allocated to the Company's gas operations was derived from the response to data request PSC-2-6, which was issued to DPL in Docket No. 09-182.

Q. Why have you used a two-year period rather than a three-year period for determining a normalized amount for pensions?

A. Adding in the third year (2007) to the two years used (2008 and 2009) would significantly <u>reduce</u> the amount of the recommended normalized allowance. For 2007, DPL's Delaware gas Distribution operations had negative pension expense (i.e., net pension income of $127,834[9]) and including that in a three-year average would produce an average amount of only $1,247,374, which does not appear to be representative of recent levels or going forward expectations.

Q. Why are you not using 2010 in the average?

A. The 2010 amounts reflect the impact of the abnormal market conditions in late 2008 and early 2009. The use of an average of 2008 and 2009 is also consistent with Staff's recommendation in the recent DPL electric rate case, and is consistent with the Hearing Examiner's recommendation in that case. The defined benefit pension plans are the same for DPL electric and DPL gas, so consistency for DPL electric and DPL gas on this issue in their respective rate case is appropriate.

Q. What adjustment should be made to the filing?

A. Schedule RCS-13 shows the adjustment that is necessary to set the pension expense in rates based on the average of the 2008 and 2009 pension expense. The schedule incorporates the actual 2008 pension expense (pension income of $42,423 on a DPL gas distribution-related basis and the 2009 pension expense of $3,912,379 on a DPL gas distribution-related basis in deriving the average. As shown in the schedule, the pension

[9] See, e.g., the Company's response to data request PSC 2-6 in Docket No. 09-182.

expense included in DPL's filing should be reduced from $3,166,916 on a DPL gas distribution-related O&M expense basis to $1,934,978. The impact is a reduction to the Company's O&M expense of $1,231,938.

NOI-3, Regulatory Commission Expense

Q. Please explain DPL's pro forma adjustment to regulatory commission expense.

A. On Schedule WMV-4 (Adjustment No. 3) from DPL's 12+0 Update, the Company presented its proposed pro forma adjustment to regulatory commission expense. DPL's adjustment for this item is comprised of two items. The first part of the Company's adjustment was to normalize the test period amount of regulatory commission expense by calculating a three-year average using the 12 months ended June 30 of 2008, 2009 and 2010. The second part of the Company's adjustment was to amortize the estimated costs of the instant proceeding over a three-year period with the unamortized balance being included as part of rate base. I removed the unamortized balance from rate base as discussed in the earlier section of my testimony related to Staff adjustment RB-2 which is reflected on Schedule RCS-7. DPL also included a $50,000 estimate related to DPA charging the Company for certain regulatory activities.

Q. Other than removing the unamortized balance of the current case costs from rate base, are you recommending an additional adjustment to DPL's pro forma regulatory commission expense?

A. Yes. I recommend that the cost of the current proceeding be normalized over a four-year period versus the three-year amortization period proposed by DPL. The Company's last gas base rate case was in 2006 in Docket No. 06-284.[10] The reason for normalizing regulatory commission expense is to reflect the level of such expense that DPL would incur in each year during the rate effective period. Since the Company's last gas base rate case was four years ago, use of a four-year normalization period is more appropriate for ratemaking purposes.

Q. Please summarize your adjustment to regulatory commission expense.

A. As shown on Schedule RCS-14, my use of a four-year normalization period for the current proceeding's cost decreases O&M expense by $56,167.

NOI-4, Wage and Salary Expense

Q. Please explain Staff Adjustment NOI-4.

A. This adjustment, shown on Schedule RCS-15, reflects the removal of the Company's estimated three percent wage increase to non-union employees which DPL indicated would be implemented in March 2011 and reflected on Company Adjustment No. 3 from its 12+0 Update.

Q. Please explain why you are recommending this adjustment.

A. While I understand the Company's need to attract, retain and motivate its employees, given the current state of the U.S. economy, I believe that the Company's proposed adjustment to increase wage and salary expense beyond 2010 would place an undue burden on ratepayers. Additionally, the 2011 non-union increase is not known and

[10] Per DPL's response to data request DPA-44.

measurable, and may not be implemented. Therefore, I am recommending that the Company's projected 2011 wage increase for non-union employees be disallowed.

Q. Are you recommending a similar adjustment for DPL's union employees?

A. No. As part of Company Adjustment No. 3, DPL also included a two percent wage increase for both IBEW Local 1238 and IBEW Local 1307. Unlike the estimated three percent wage increase that DPL is proposing for its non-union employees, the two percent wage increases proposed for IBEW Locals 1238 and 1307 are included in the final key term sheets of the IBEW Local 1238 and Local 1307 union contracts that will be in effect during the rate effective period. The referenced final key term sheets were provided in the Company's response to data request PSC-LA-123. Since the two percent wage increases for DPL's union employees are included in the union contracts that will be in effect during the rate effective period, they are known and measurable and therefore should be allowed.

Q. Please summarize your adjustment to wage and salary expense.

A. As shown on Schedule RCS-15, my recommended adjustment reduces the Company's O&M expense by $436,448.

NOI-5, Payroll Tax Expense

Q. Please explain Staff Adjustment NOI-5.

A. My recommended adjustment to DPL's payroll tax expense is made in conjunction with the recommended adjustment to wage and salary expense discussed in the previous section and shown on Schedule RCS-15. Based upon my recommendation to eliminate the 2011 estimated wage increase for non-union employees as shown on Schedule RCS-16, I have reduced payroll tax expense by $33,388.

NOI-6, Non-Executive Incentive Compensation Expense

Q. Please explain Staff Adjustment NOI-6.

A. This adjustment, shown on Schedule RCS-17, reduces O&M expense by $935,045, which reflects the removal of non-executive incentive compensation related to safety and non-safety related incentive compensation.

Q. How did the Commission address the issue of non-executive incentive compensation expense attributable to achievement of financial goals in the Company's last Delaware gas rate case?

A. Delmarva's last gas distribution base rate case, Docket No. 06-284, resulted in a "black box" settlement that did not address specific issues except for the return on equity and the capital structure. In Docket No. 05-304, the Company's most recent electric base rate case in which the Commission rendered a decision, the Commission excluded from the Company's cost of service the amount of non-executive incentive compensation expense attributable to achievement of financial goals, concluding that since shareholders benefit from the achievement of those goals, shareholders should pay for them. *In the Matter of the Application of Delmarva Power & Light Company for a Change in Electric Distribution Base Rates and Miscellaneous Tariff Changes*, PSC Docket No. 05-304, Order No. 6930, ¶¶ 96-98 (June 6, 2006).

Q. What has the Company proposed in the current case?

A. The Company included $935,045 of non-executive incentive compensation expenses in this case, arguing that the incentives are part of non-executive employees' total compensation package and that they benefit customers by extending the period between rate cases. The Company contended that: (1) the AIP motivates employees to another level of engagement which translates to additional discretionary effort of going above and beyond in order to serve customers better; (2) the AIP saves money both directly and indirectly in terms of increased productivity and reliability, as well as safety, that is directly passed onto customers in future ratemaking (3) the AIP reinforces a team oriented and participative culture, and (4) incentives as a key component of total compensation allow the Company to compete in the marketplace to hire and retain the best talent. (Jenkins Direct Testimony at pp. 10-11).

Q. How was the issue of Delmarva's non-executive compensation expenses addressed in Delmarva's recent electric distribution rate case?

A. In PSC Docket No. 09-414, Staff removed Delmarva's non-executive compensation expenses, based in part on the decision in Docket No. 05-304. This adjustment was discussed in Staff's Opening Brief dated June 22, 2010 at pages 16-21 and later reiterated in Staff's Reply Brief dated July 8, 2010 at pages 30-31. The Commission had not considered the matter at the time of this testimony. However, the Hearing Examiner's report, issued October 1, 2010, at pages 69-70, agrees with Staff that this expense should be removed from DPL's cost of service.

Q. How has Staff addressed non-executive compensation expenses in the current DPL gas rate case?

A. Staff removed all non-executive compensation expenses based in part on the decision in Docket No. 05-304, but also due to the current economic climate in the State of Delaware, which has worsened considerably since the Commission issued its Order in Docket No. 05-304. During the period January through August 2010, the unemployment rate in Delaware has averaged 8.8%.[11] In contrast, Delaware's unemployment rate was only 3.7% - 3.8% in April-May 2006 when the Commission conducted its deliberations in Docket No. 05-304.

Q. Please discuss the Company's Annual Incentive Plan.

A. Similar to the plans at issue in Docket No. 05-304, the 2010 Annual Incentive Plan ("AIP") (the only one produced in response to a request for *all* such plans per data request DPA-19) provides that payouts will be made *only* upon attaining overall corporate earnings thresholds of 90% for Corporate Services employees and 93% for Utility Operations employees. The AIP is driven first and foremost by financial performance, which benefits shareholders.

Q. Please respond to the Company's position that the AIP helps attract, retain and motivate employees to provide safe and reliable service.

A. The Company made these same arguments Company in Docket No. 05-304. The Company has not provided evidence suggesting that safety and reliability would be

[11] State of Delaware Department of Labor website.

adversely affected if did not make such payments. Indeed, the AIP specifically provides that it can be terminated at any time.

Q. What other arguments has Delmarva advanced for charging ratepayers for non-executive incentive compensation expense?

A. The Company reiterates similar arguments to the ones it advanced in its rebuttal testimony in Docket No. 05-304:

- Delmarva designs its compensation plan to be in the middle of the competitive labor market.
- Delmarva could cut the incentives and increase base salaries, but management decided to pay lower base salary and provide the opportunity to earn higher performance-based rewards.
- The AIP helps focus employees' attention and efforts on achieving company goals, many of which are explicitly customer-oriented. To the extent other goals are financial, this helps motivate employees to keep costs down and benefits ratepayers.
- The specifics of the incentive programs differ from job to job or among levels but all have employee measures such as safety and all have customer satisfaction components. Although all have financial components such as O&M expense control, managing capital expenditures and achieving targeted income levels, achieving these goals reduces the Company's revenue requirement.
- The AIP's financial goals benefit customers by allowing Delmarva to set reasonable investment levels to meet reliability, safety and service obligations and commitments at reasonable cost.
- The AIP ensures that employees are spending money carefully and taking care of the Company's assets.
- The AIP can lengthen the period between rate cases and mitigate the size of rate increases when cases are filed.
- A portion of AIP expense is attributable to achievement of safety, customer service or reliability goals. [12]

Q. Please respond to those arguments.

[12] Jenkins Direct Testimony at 9-11.

A. These arguments are even more unpersuasive now than they were in Docket No. 05-304. First, unlike the plans at issue in Docket No. 05-304, the AIP is devoid of any specific reference to the achievement of safety/customer satisfaction/reliability goals. Payment is only made under the AIP if the earnings thresholds are achieved, *regardless* of whether the safety and customer service goals are met.

Second, the PHI-system total amounts expensed in 2009 significantly exceeded the amounts expensed in any of the preceding three years. Between 2006 and 2009, the system-wide payout level ranged from $12,105,426 to $17,489,190.[13]

Furthermore, it is possible that no incentive compensation payments would be made in any given year. In that case, including an allowance for such payments in the Company's revenue requirement would result in ratepayers paying an expense that the Company is not incurring.

Finally, ratepayers should expect Delmarva employees to provide quality performance even without an incentive program. Employees would not reduce the quality of their performance if their incentive compensation were reduced or not included in rates. Delmarva would be able to meet its statutory obligation to provide safe, adequate and reliable service without ratepayer-funded incentive payments.

The Commission considered each of the Company's arguments here in Docket No. 05-304, and ultimately found them wanting in light of the fact that the plans at issue there were primarily driven by financial goals. Here, the AIP is purely driven by financial goals since achievement of earnings thresholds is the only way any payment gets made regardless of whether the safety/customer service/reliability goals are met.

[13] Per DPL's response to data request DPA-19.

Q. Please summarize Staff's recommended adjustment for non-executive incentive compensation.

A. The Company can pay non-executive employees incentive compensation that is based upon financial triggers. However, if it does, the ones who benefit from the achievement of the financial goals – the shareholders – should pay for those benefits. Unlike customers of competitive companies who can take their business elsewhere if the cost of a product or service is too high, DPL's ratepayers have no choice. As shown on Schedule RCS-17, this adjustment reduces DPL's O&M expense by $935,045.

NOI-7, Executive Compensation Expense

Q. Please explain Staff Adjustment NOI-7.

A. This adjustment reflects the removal from cost of service of several items of executive compensation provided to the Company executive and officers listed in PHI's 2009 Proxy Statement. I removed the following components of executive compensation from cost of service because none of these items is necessary for the provision of safe and reliable gas service to DPL's ratepayers:

1. Dividends Paid on Unvested Shares of Restricted Stock.
2. Company Matching Contributions on Deferred Compensation.
3. Tax Preparation Fees
4. Financial Planning Fees
5. Club Dues
6. Spousal Travel
7. Employment Transition Expenses

Q. Please summarize your adjustment to executive compensation.

A. As shown on Schedule RCS-18, after applying the appropriate allocation factors, my adjustment reduces O&M expense for DPL's gas operations by $18,853.

NOI-8, Stock-Based Compensation Expense

Q. Please explain Staff Adjustment NOI-8.

A. This adjustment, shown on Schedule RCS-19, reduces O&M expense by $168,630.

Q. Please discuss the reasons for removing stock-based compensation.

A. Ratepayers should not be required to pay executive or director compensation that is based on the performance of the Company's (or its parent company's) stock price, or which has the primary purpose of benefitting the parent company's stockholders and aligning the interests of participants with those of such stockholders.

Additionally, prior to being required to expense stock options for financial reporting purposes under Statement of Financial Accounting Standards No. 123 Revised (SFAS 123R), the cost of stock options was typically treated as a dilution of shareholders' investments, i.e., it was a cost borne by shareholders. While SFAS 123R now requires stock option cost to be expensed on a company's financial statements, this does not provide a reason for shifting the cost responsibility for stock-based compensation from shareholders to utility ratepayers.

Q. What is the effect of your recommended adjustment for DPL's Stock-Based Compensation expense?

A. As shown on Schedule RCS-19, this adjustment decreases test period O&M expense by $168,630.

NOI-9, Supplemental Executive Retirement Program Expense ("SERP")

Q. Please explain Staff Adjustment NOI-9.

A. This adjustment, shown on Schedule RCS-20, removes 100% of the expense for the SERP. The SERP provides supplemental retirement benefits for select executives. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company's contributions to 401(k) plans such that the Company's contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Why should SERP expense be removed?

A. The SERP provides retirement benefits to Company executives over and above the many benefits that they already receive under PHI's other retirement plans. Staff has removed the SERP benefits from the Company's cost of service on the ground that ratepayers should not be burdened with funding these additional benefits, especially in the current economic climate.

Q. What reasons did DPL present in its recent electric utility distribution rate case for charging the cost of SERP to ratepayers?

A. In its rebuttal in PSC Docket No. 09-414 et al, the Company contended that its actuary had concluded that the benefits provided under the Company's qualified and SERP plans at normal retirement age were "below the median of those provided by the firms in the peer group" of utilities identified in PHI's 2008 proxy statement. Because of this, DPL witness Mr. Jenkins argued, the Company was at a disadvantage with respect to retaining executive talent, and removing the SERP expenses from the Company's cost of service would exacerbate that claimed disadvantage.[14]

Q. Please respond to that position.

A. This argument is no more persuasive in this context than it was in the context of incentive compensation benefits. SERP is additional executive compensation over and above what these executives will receive as part of the normal retirement benefits that are provided to other employees. The additional SERP benefits are not necessary for the provision of safe, adequate and reliable utility service. If the Company wants its executives to have these additional benefits, shareholders should pay for them.

Q. Was SERP expense also disallowed in the Hearing Examiner's recommended decision in the rate case involving DPL's affiliated electric utility operations?

A. Yes, it was.

Q. What adjustment related to DPL's SERP expense do you recommend?

A. I recommend removing SERP expenses from cost of service, which reduces O&M expense by $190,184.

NOI-10, AFUDC

Q. Please explain Staff Adjustment NOI-10.

[14] Jenkins Direct Testimony at page 3.

A. This adjustment is shown on Schedule RCS-21 and removes the AFUDC from net operating income. This adjustment is related to Staff Adjustment RB-3 to remove CWIP from rate base.

Q. How does DPL accrue a return on construction projects?

A. DPL accrues a return, representing its financing costs during the construction period, called AFUDC. This AFUDC return accounts for the utility's financing cost during the construction period. When the plant is placed into service, the AFUDC becomes part of the cost of the plant and is depreciated.

Q. What amount of AFUDC did DPL include in its operating income statement and how does that compare with the amount of CWIP that DPL proposes to include in rate base?

A. As discussed previously, in its 12+0 Update, DPL included $2,196,480 of pro forma CWIP in rate base, and included a pro forma AFUDC offset of $2,018 in other operating revenue.

Q. Why should the AFUDC be removed from the operating income statement?

A. Consistent with the removal of CWIP from rate base, the related AFUDC should be removed from the operating income statement for proper matching.

Q. Does Schedule RCS-21 reflect an additional adjustment to AFUDC?

A. Yes. As discussed in more detail in a later section of my testimony as it relates to Staff Adjustment NOI-15, in its AMI Supplemental Testimony, DPL removed its pro forma adjustments related to AMI. Company Adjustment No. 19, which related to AMI net plant additions, included the removal of AFUDC in the amount of $11,504. My adjustment to AFUDC shown on Schedule RCS-21 reflects the negative $11,504 which results in a net adjustment of ($9,486). The effect of offsetting this amount against my adjustment to reverse the AFUDC component of DPL Adjustment No. 19 results in AFUDC netting to zero.

NOI-11, Interest Synchronization

Q. Please explain Staff Adjustment NOI-11.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule RCS-22. This adjustment increases income tax expense by the amount shown on Schedule RCS-22 and decreases the Company's achieved operating income by a similar amount.

NOI-12, Membership and Industry Association Dues

Q. Please explain Staff Adjustment NOI-12.

A. This adjustment, shown on Schedule RCS-23, reduces expenses for membership and industry association dues by $45,721, which includes reducing the test period level of dues paid to the American Gas Association ("AGA") and removes entirely dues paid to the Gas Professional Association Memberships ("GPAM").

Q. Please explain Staff's proposed adjustment for AGA dues.

A. This adjustment, shown on line 1 of Schedule RCS-23, reduces test period expense by $44,421 to reflect the removal of 40 percent of AGA dues.

Q. What information did DPL provide concerning the specific benefits of AGA activities to the Company and Delaware ratepayers?

A. DPL provided little information concerning the benefits of AGA membership. The AGA does provide some benefit to the utilities that comprise its membership; however, this does not negate the fact that a significant portion of AGA expenditures are related to programs which should be disallowed for ratemaking purposes. I have attached to my testimony a listing and description of the AGA's functions as listed in the March 2005 Annual Audit Report to the National Association of Regulatory Utility Commissioners (NARUC), and have identified the percentage of AGA activities related to each function.

There is some benefit of AGA membership to the Company and to Delaware ratepayers from some of the AGA's functions. However, the Company has failed to demonstrate that ratepayers should fund activities conducted through an industry organization that would be subject to disallowance if conducted directly by the utility, such as lobbying or image building advertising. The Company has failed to demonstrate that all of its AGA dues should be charged to ratepayers. As I will discuss below, utilities in other states have reduced the level of AGA dues claimed in their cost of service, similar to my recommendation.

I have become aware of AGA dues disallowances made in gas utility rate cases in Michigan and California. In California, it appears that Pacific Gas and Electric Company itself reduced the amount of AGA dues claimed by 25 percent in its filing in Application 05-12-002 (filed 12/2/05) as related to lobbying in the broader sense. In a more recent California rate case, San Diego Gas and Electric appears to have proposed a 2 percent AGA dues disallowance for lobbying in the narrowest sense; the Division of Ratepayer Advocates proposed that the entire cost of SDG&E's AGA dues be excluded; and the Utility Consumers' Action Network ("UCAN") supported either full disallowance or a 25 percent disallowance based on the result from the PG&E rate case and its review of information regarding AGA activities (Application No. 06-12-009).[15]

In Michigan, Consumers Energy Company's gas utility operations[16] conceded to a PSC Staff adjustment to disallow 16.17 percent of AGA dues. As described in the testimony of MPSC Staff witness Wanda Clavon Jones.[17]

> Staff adjusted dues to eliminate activities that would not be allowed if the Company took on those activities for themselves. These activities include Public Affairs (15.43%) and Media Communication-Promotion (0.74%). Staff obtained the information necessary to make this adjustment from the Audit Report on Expenditures of the American Gas Association issued June 2001. The total disallowance is 16.17%, or $60,780. This disallowance is consistent with the last rate cases of Consumers, MichCon and MGU.

Q. How have other regulatory commissions recently addressed the issue of the appropriate portion of AGA dues to disallow for ratemaking purposes?

[15] A final order has apparently not been issued yet in the SDG&E rate case, which has been reopened.
[16] Michigan PSC Case No. U-13000.
[17] Filed 12/14/2001, at page 6.

A. The Arizona Corporation Commission ("ACC") disallowed 40 percent of AGA dues in Decision No. 70665, in the most recent Southwest Gas rate case. (Docket No. G-01551A-07-0504). In Decision No. 70665, at page 12, the ACC stated:

> "We find that Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit."

Additionally, in Docket No. G-04204A-08-0571, the ACC removed 40 percent, or $18,678, of UNS Gas, Inc.'s $46,694 test year expense for AGA membership dues, consistent with the analysis described above, and consistent with Decision No. 70665.

Q. How did you determine the percent disallowance for AGA dues?

A. This was based upon a review of information in the two most recent NARUC sponsored Audit Reports of the Expenditures of the American Gas Association, as well as the components by function of the AGA's 2007 and 2008 budgets. I also relied upon a Florida PSC Staff memorandum, discussed in more detail below, which contained a 40 percent AGA dues disallowance. Copies of the relevant pages from the NARUC-sponsored audit reports are provided in Appendix D. AGA 2007 and 2008 budget information, by component, is summarized on Schedule RCS-23, page 2.

Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?

A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide regulatory commissions with information to help them decide what amount, if any, of AGA dues should be approved for inclusion in utility rates. As stated in a June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. Have other regulatory commission required similar adjustments to utility-incurred AGA dues, based on the results of the NARUC-sponsored audits?

A. Yes. As an example, I have included in Appendix E, an excerpt from a Florida Public Service Commission Staff Memorandum (dated 12/23/03) in a City Gas Company rate case addressing this issue. As stated in that document:

> In City Gas's last rate case, *In re: Request for rate increase by City Gas Company of Florida*, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. *In re: Application for a rate increase by City Gas Company of Florida*, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." *In re: Request for rate increase by Florida Division of Chesapeake*

Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

Q. Please explain your adjustment to remove membership dues paid to the GPAM.

A. As shown on Schedule RCS-23, I removed test period dues paid to the GPAM in the amount of $1,300. I removed this amount because when I attempted to research this organization, not only could I not find any information that explained the functions of the GPAM, I could not even verify the existence of this organization. In fact, when I attempted to Google the GPAM, the result was “No results found for “Gas Professional Association Memberships.”

Q. Please summarize your adjustment to membership and industry association dues.

A. As shown on Schedule RCS-23, I have reduced O&M expense by $45,721.

NOI-13, Employee Benefits (Medical, Dental and Vision)

Q. Please explain the Company's pro forma adjustment to employee benefits for medical, dental and vision expenses.

A. As shown on Schedule WMV-8 (Adjustment No. 10) in DPL's 12+0 Update, the Company adjusted test period O&M expense to reflect an eight percent increase in medical expenses and a five percent increase in dental and vision expenses. This adjustment is predicated on the work conducted by DPL's benefits consultant Lake Consulting, Inc. ("Lake"), as discussed in the direct testimony of Company witnesses Von Steuben and Jenkins.

Q. Do you agree with the Company's pro forma adjustment to increase employee benefits for medical, dental and vision expenses?

A. No, I do not. As noted above, the Company based its adjustment on Lake's study, which consisted of a regional medical trend survey of six companies in the Maryland, Virginia and Washington D.C. areas.[18] However, it does not appear that Lake's study took into account several modifications the Company has made or will be making to its benefit plans as it relates to medical, dental and vision expenses.

[18] The Company provided Lake Consulting, Inc.'s study in the response to data request DPA-98.

Q. Please describe the modifications that have been or will be made to the Company's benefit plans as it relates to medical, dental and vision expense.

A. As DPL discussed in the response to data request PSC-LA-146, changes to the Company's benefits plan design in 2010 includes health plan vendor consolidation and the elimination of the Company's fully insured HMO plans for executives, management and union employees. In addition, all management employees, including executives, have increased medical plan co-pays as well as mandatory mail order prescription drug coverage.

Beginning January 1, 2011, the amount of management employees' monthly contributions to the plan will increase. DPL will also increase deductibles for the PHI PPO plan in 2011. Co-pays are scheduled to increase for PHI's PPO and HMO plans effective January 1, 2012. Changes to the medical plans available to IBEW Local 1238 include the elimination of the Standard Indemnity for all members as well a requirement for new hires to participate in PHI's HMO or PPO under the same changes described above for management employees. In addition, members of Locals 1237 and 1238 contribute 20 percent of the cost of medical and mental health/substance abuse benefits per their union agreement.[19] Finally, management employees contribute 17.5 percent and 18 percent towards PHI's PPO and HMO plans, respectively.[20]

Q. Did Staff request that DPL show whether the changes to the Company's benefit plans described above have been reflected in its pro forma adjustment for medical, dental and vision expenses?

---

[19] Per DPL's responses to data requests PSC-LA-145 and DPA-34.
[20] Per DPL's responses to data requests PSC-LA-145 and DPA-34.

A. Yes. Data request PSC-LA-245 asked the following:

> "Refer to the response to DPA-34. **Show in detail** how the employee contribution rates towards the cost of medical etc. insurance has been reflected in the calculation of pro forma employee benefits expense."
>
> (Emphasis supplied)

In response to PSC-LA-245, the Company stated:

> "Any impact from Company cost for a single employee cost of employee contribution rates towards the cost of medical and other benefits has been factored in the Company's pro-forma adjustments."

As can be seen from the Company's response, DPL did <u>not</u> show in detail or otherwise quantify that the plan changes described in the preceding section are (1) reflected in Lake's study, or (2) factored into the Company's pro forma adjustment.

Q. Please describe any other areas of concern related DPL's pro forma adjustment to medical, dental and vision expense.

A. In response to data request DPA-33, which asked DPL to provide the most recent unit rates for the Company's medical and dental benefit plans, the Company provided the following data, which is as of September 2010:

MEDICAL PLANS

Employee Monthly Cost	Employee Count
$ 365.61	428
$ 377.17	4
$ 321.24	635
$ 351.73	68
$ 369.49	32
$ 120.66	5
$ 371.38	55
$ 406.00	197
$ 511.39	3

Employee + 1 Monthly Cost	Employee + 1 Count
$ 731.20	286
$ 755.87	6
$ 642.46	554
$ 705.01	50
$ 740.53	47
$ 242.85	4
$ 744.28	49
$ 813.55	258
$ 1,021.09	5

Family Monthly Cost	Family Count
$ 1,096.81	307
$ 1,133.82	4
$ 963.70	831
$ 1,057.51	74
$ 1,110.80	89
$ 364.29	0
$ 1,116.44	46
$ 1,220.33	386
$ 1,587.34	4

DENTAL PLAN

Employee Monthly Cost	Employee Count
$ 36.29	1347

Family Monthly Cost	Family Count
$ 89.63	3185

Data request PSC-LA-244 asked DPL to reconcile the rates listed in the tables above to the rates used in the Company's pro forma adjustment (Adjustment No. 10). In response, the Company stated in part:

> The attached illustrates the Company's cost for a **single employee only** coverage for 2010 in comparison to 2009. The Lake Consulting Survey used for the Employee Benefits pro-forma adjustment includes an annual trend of 8% medical expenses based on the responses from regional insurance carriers…The costs for the plans shown in the attachment are based on actual claims experience of the plan and average enrollment during the cost rate-setting period…While the Company utilizes the Lake Consulting survey for its employee benefits forecast, there is greater variability in each plan's performance due to smaller risk pools and actual experience…

(Emphasis supplied).

The table below reproduces the data in the attachment referred to in the passage above from PSC-LA-244. As shown in the table, the overall average percentage change between 2009 and 2010 expenses for single employee only coverage is actually a 3.40 percent *decrease* in such costs.

Employee Only Cost

Item	2010	2009	Variance
Medical			
PHI PPO	$ 365.61	$ 370.67	-1.37%
PHI HMO	$ 321.24	$ 301.00	6.72%
CIGNA PPO	$ 351.73	$ 346.50	1.51%
Aetna QPOS	$ 369.49	$ 512.17	-27.86%
Basic Indeminity	$ 120.66	$ 137.83	-12.46%
Standard Indeminity	$ 371.38	$ 474.42	-21.72%
Carefirst PPO	$ 406.00	$ 401.22	1.19%
Carefirst EPO	$ 511.39	$ 473.99	7.89%
Dental	$ 36.29	$ 35.57	2.02%
Vision	$ 14.21	$ 12.91	10.07%
Average Percentage Change			-3.40%

It should be noted that DPL did not provide a similar reconciliation as it relates to its Employee & 1 and Family plans.

Q. What is your recommendation?

A. Since the Company has not demonstrated that the modifications to its benefits plans were reflected in Lake's study or factored into its pro forma adjustment, I recommend that DPL's adjustment to increase pro forma medical expense by eight percent and dental/vision expense by five percent be rejected. Therefore, by reversing Company Adjustment No. 10 from its 12+0 update filing, as shown on Schedule RCS-25, I have reduced O&M expense by $315,158.

NOI-14, AMI Expense Revisions (DPL Adjustments 18 through 20)

Q. Please explain Staff Adjustment NOI-15.

A. As shown on Schedule RCS-26, this adjustment reflects the removal of DPL's pro forma expense adjustments 18, 19 and 20 based on DPL's AMI Supplemental Testimony. The reduction to pre-tax operating expenses related to DPL's revision of those Company-proposed adjustments is summarized in the following table:

Company Revision to Pre-Tax AMI-Related Operating Expenses

DPL Adj. No.	Description	Per DPL12+0 Filing	Per DPL10-11-2010 AMI Update Filing	DPL Revision (Decrease) Increase
		(A)	(B)	(C)
18	AMI Net O&M Expense	$ (967,773)	$ -	$ 967,773
19	AMI Net Plant Additions		$ -	
	Depreciation Expense	$ 1,153,934	$ -	$ (1,153,934)
20	AMI Stranded Costs	$ 9,767	$ -	$ (9,767)
	Totals	$ 195,928	$ -	$ (195,928)
	Net Reduction to Pre-Tax Operating Expense			$ (195,928) *

Source
Col.A DPL 12+0 Update, Schedules JCZ-6, JCZ-7 and JCZ-8 (Adjustment Nos. 18, 19 and 20, respectively)
Col.B DPL's 10-11-2010 AMI Supplemental Filing, Schedules JCZ-6 through JCZ-9 AMI Supplemental

* Company Adjustment No. 19 also reflects the removal of AFUDC in the amount of $11,504

NOI-15, AMI Deferred Costs

Q. Please explain Staff Adjustment NOI-16.

A. Similar to Staff Adjustment NOI-15, this adjustment reflects the Company's revision to Adjustment No. 21 pursuant to the AMI Supplemental Testimony. The Company's AMI deferred cost adjustment reflects a similar uncontested adjustment made by DPL in the Company's pending Delaware electric base rate case Docket No. 09-414. As shown on Schedule RCS-27, the difference between the Company's revised Adjustment No. 21 and that included with its 12+0 Update, results in a $53,220 reduction to amortization expense.

NOI-16, Gas Decoupling Customer Education Expense

Q. Please explain DPL's proposed Adjustment No. 10.

A. As discussed on page 14 of Mr. Von Steuben's direct testimony, the Company is proposing a decoupling customer education program designed to help customers understand how DPL's new rate design will impact them going forward. Mr. Von Steuben stated that a program is being designed and will be implemented concurrently with the new rate design. As shown on Schedule WMV-10 (Adjustment No. 14) from DPL's 12+0 Update, the Company has made a pro forma adjustment to increase O&M expense in the amount of $106,500 pursuant to the planned decoupling customer education program.

Q. Is the $106,500 an actual expense that the Company has incurred?

A. No. Data request DPA-103 asked the Company to provide all supporting calculations, workpapers and documentation for the $106,500 of decoupling customer education costs. In response, the Company stated:

> The amount that the Company included in the filing for gas customer education costs is an estimate. The anticipated timing to implement gas decoupling is at the end of this gas base rate case, and the Company will be engaging in education of customers at that time. The breakdown of costs are as follows:
>
> $45,000 – Newspaper Ad regarding gas decoupling
> <u>$61,500</u> – Direct mailing of decoupling educational material
> $106,500

In addition, data request PSC-LA-273 asked DPL to provide (1) the decoupling educational materials that were direct mailed to customers; (2) the newspaper ad(s) for decoupling the decoupling program; and (3) to indicate whether any of the $106,500 has been spent, and if so, how much. In response, DPL essentially repeated its response to

DPA-103 in that the anticipated timing of implementing the gas decoupling program will be at the conclusion of this proceeding. As a result, no decoupling educational materials have been mailed to customers, nor have any newspaper ads been placed yet. In addition, the Company reiterated that the $106,500 is an estimate and none of it has been spent.

Q. What is your recommendation?

A. The proposed decoupling customer education program has not been designed yet. In addition, none of the decoupling educational materials have been mailed to customers and none of the decoupling newspaper ads have been placed yet, the $106,500 is only an estimate, and none of it has been spent. As such, the Company has not demonstrated that this amount is known and measurable. Therefore, as shown on Schedule RCS-27, I have reversed the Company's pro forma adjustment related to its proposed gas decoupling customer education program, which reduces O&M expense by $106,500.

NOI-17, Meals and Entertainment Expense

Q. Please explain Staff Adjustment NOI-17.

A. This adjustment is shown on Schedule RCS-28 and reduces O&M expense by $12,900. Data request DPA-53 asked DPL to provide the level of meals and entertainment expenses included in the test period but disallowed for income tax purposes. In response, the Company indicated that the total Company amount of meals and entertainment expense for the 12 months ended June 30, 2010 test period was $462,741. This amount compares to a total Company amount of $281,018 for the 12 months ended March 31, 2009. In response to data request PSC-LA-248, DPL explained that the $181,723 difference ($462,741 - $281,018) between the test period and the 12 months ended March 31, 2009 was due primarily to meals associated with 2010 winter snowstorms and the June 2010 strike. The response to PSC-LA-248 also provided comparable data for calendar years 2007, 2008 and 2009 in the amounts of $259,990, $318,360 and $257,018, respectively. Since the test period level of meals and entertainment expense were abnormally high due to the snowstorms and June 2010 strike, it is necessary to normalize such expenses to reflect a representative level during the rate effective period.

As shown on Schedule RCS-28, I have normalized meals and entertainment expenses based on an average of the three-year period 2007, 2008 and 2009. After applying the seven percent allocation factor applicable to DPL's Delaware gas operations, this adjustment reduces O&M expense by $12,900.

Other Issues – O&M Expense Increases For AMI-Related Labor Costs

Q. Did DPL revise any of its pro forma adjustments upon filing its AMI Supplemental Testimony beyond the AMI-related adjustments discussed previously?

A. Yes. The Company revised the following four pro forma adjustments upon filing its AMI Supplemental Testimony beyond the AMI-related adjustments previously discussed in my testimony:

1. Schedule WMV-5 (Adjustment No. 3) – Wage, Salary and FICA Expense.
2. Schedule WMV-8 (Adjustment No. 10) – Medical/Dental/Vision Costs.
3. Schedule JCZ-4 (Adjustment No. 11) – Pension Expense
4. Schedule JCZ-5 (Adjustment No. 12) – OPEB Expense

Q. What is the nature of the revisions to the aforementioned pro forma adjustments?

A. In its original "6+6" filing and in its "12+0" Update, as part of each of the pro forma adjustments referenced above, the Company removed "AMI related costs" in determining the pro forma amounts that it proposed to include in cost of service for the rate effective period. Upon filing its AMI Supplemental Testimony, the Company revised these adjustments by "adding back" the AMI-related costs that were initially removed in the "6+6" filing and "12+0"Update. The amounts added back through the Company's revised adjustments are as follows:

1. Adjustment No. 3 – AMI Related Wage, Salary and FICA Expense - $708,756
2. Adjustment No. 10 – AMI Related Medical/Dental/Vision Costs – $105,150
3. Adjustment No. 11 – AMI Related Pension Expense - $76,524
4. Adjustment No. 12 – AMI Related OPEB Expense - $82,200

Q. For each of the pro forma adjustments listed, did the Company explain why it added back the AMI-related costs in its AMI Supplemental Testimony?

A. No. The AMI Supplemental Testimony of Company witnesses Von Steuben (concerning Company Adjustment Nos. 3 and 10), and Ziminsky (concerning Company Adjustment Nos. 11 and 12), merely mentioned these adjustments, but did not explain why AMI-related labor costs were now increasing test period O&M expense.

Q. Have you reflected the revised pro forma adjustments referenced above in the determination of your recommended revenue requirement for DPL?

A. No. As noted above, the Company's AMI Supplemental Testimony did not explain or justify why AMI-related labor expenses that were removed in the Company's "6+6" filing and "12+0" Update should be included in adjusted test period O&M expense. Additionally, the timing of the AMI Supplemental Testimony did not lend itself to normal discovery in which an explanation for these adjustments could have been requested and obtained. Therefore, I have not reflected these AMI-related expenses in the determination of my recommended revenue requirement for DPL. Any Company rebuttal related to these AMI meter related labor costs should address the attrition of full time meter reading positions and/or replacement with temporary personnel in light of the initial AMI deployment schedule and the Company's focus on moving full time meter reading employees into other Company positions and/or those who may have moved on due to retirement or other work opportunities.

<u>Summary of Net Operating Income</u>

Q. What adjusted net operating income do you show for DPL after making Staff's recommended adjustments?

A. As shown on Schedule RCS-4, the adjusted net operating income for DPL's gas distribution operations is $15,709,575 after making Staff's recommended adjustments.

Normalized Uncollectibles Expense Methodology

Q. Has an issue come to your attention concerning the calculation of uncollectibles?

A. Yes. DPL proposed to normalize uncollectible expense using a three-year average of uncollectible expense for the 12 months ended June 2008, 2009 and 2010. It did not propose to use a three-year average of net write-offs as a percentage of revenues.

Q. How have DPL's uncollectibles expense and net write-offs for its Delaware gas utility operations fluctuated?

A. The following table shows the amounts for each 12 month period ended June 2008, 2009 and 2010, as well as the annual differences.

Uncollectibles Expense*

12 Months Ended		Uncollectibles Expense	Change From Prior Year
6/30/2008	$	2,177,979	
6/30/2009	$	3,073,344	$ 895,365
6/30/2010	$	2,502,549	$ (570,795)

Net Write-Offs*

12 Months Ended		Uncollectibles Expense	Change From Prior Year
6/30/2008	$	2,498,951	
6/30/2009	$	2,350,737	$ (148,214)
6/30/2010	$	2,627,466	$ 276,729

* Amounts above from DPL's response to PSC-LA-74

The amounts have fluctuated from year-to-year with no clear trend upward or downward.

Q. Do you generally believe that using net write-offs to compute the normalized amount of uncollectibles expense is preferable in most situations?

A. Yes. A rate that is calculated from a three-year average of actual net write-offs is generally a more appropriate method of normalizing uncollectibles expense. Net write-offs represent actual uncollectible accounts (bad debts) less recoveries. In contrast, the uncollectibles expense reflects the impact of accrual entries to adjust the reserve for uncollectibles. The net write-offs consist of actual amounts written off, less the recoveries during the year of amounts that had been written off. The resulting percentage of net write-offs can be applied to the adjusted test period revenues in order to determine a normalized uncollectible cost to include in base rates. If it were not for a desire to be consistent with the situation in the recent DPL electric case where Staff used a 3 year average of uncollectibles expense, I would have recommended a three-year average of net write-offs to revenue be used in this proceeding to determine the normalized amount of uncollectibles. This adjustment would have reduced Delmarva's claimed uncollectibles expense amount by $257,385.

I note that in rate cases involving almost all of Delaware's other major utilities, Staff has calculated uncollectibles the way I would have proposed by determining a normalized allowance (preferably using the relationship of net write offs to revenues, and including a provision for uncollectibles in the determination of the gross revenue conversion factor. See Docket Nos. 06-158 and 08-96 (Artesian Water Company, Inc.); Docket No. 07-186 (Chesapeake Utilities Corporation); and Docket No. 09-29 (Tidewater Utilities, Inc.). The Company should be placed on notice that hereinafter Staff will be considering whether to hold Delmarva to the same practice that the other major utilities follow for calculating the appropriate level of normalized uncollectible expense.

VI. OTHER ISSUES

Rider VM

Q. Please explain the Company's proposed Rider VM.

A. The Company proposes to recover a three-year rolling average of pension, other post-employment benefits ("OPEB"), and uncollectible expenses through a mitigation rate mechanism referred to as a Volatility Mitigation Rider ("Rider VM"). The Company would be permitted to defer for future rate treatment the difference between the average and the currently incurred amounts.[21] If Rider VM is approved, all of the costs

[21] Delmarva Direct Testimony of J. Mack Wathen, p. 7, lines 2-6.

associated with pension, OPEB, and uncollectible expense would be removed from the Company's base rates and henceforth be recovered via the Rider VM calculation.[22]

Q. Why does the Company want to implement Rider VM?

A. The Company states that the costs associated with pension expense, OPEB expense, and uncollectible expense are volatile and largely outside of management control.[23]

Q. Are these costs outside management control?

A. Contrary to the Company's contention that these items are outside management control, the Company listed a number of steps it has taken to contain costs. In particular, the Company took the following cost containment measures that directly affect OPEB and Pension expense:

- PHI eliminated subsidized retiree medical benefits for employees hired after January 1, 2005.
- Effective January 1, 2005, PHI implemented major medical plan designs changes for all eligible retirees, current and future, that eliminated the medical indemnity plan and increased deductibles, hospital co-pays, physician co-pays, and out-of-pocket maximums, which substantially increased the retirees' share of the costs for their benefits.
- PHI implemented caps that limit its retiree medical costs. Anyone retiring on or after January 1, 2005, is subject to annual medical caps. If the average annual cost per participant of all those enrolled in the medical plans (PPO or HMO) exceed the cap, additional contributions will be required from all participants (retirees and their dependents) in the following year.
- Between 2005 and 2007, PHI more than doubled the contribution that active employees and retirees must make to their medical benefits; that contribution more than tripled by the end of 2007.
- In 2009 and 2010, PHI re-bid medical plans and increased co-pays and deductibles.

[22] Delmarva Direct Testimony of J. Mack Wathen, p. 7, lines 20-23.
[23] Delmarva Direct Testimony of J. Mack Wathen, p. 6, line 23 through p. 7, line 2.

- PHI significantly reduced pension benefits for employees hired after January 1, 2005.[24]

Q. What steps has the Company taken to reduce uncollectibles?

A. Since 2003, the Company has taken the following actions to reduce its uncollectibles:

- Match-Up Report (transfer uncollectibles balances to eligible accounts) - provides the Company the ability to associate existing overdue balances with new customer sign-ups through the matching of Social Security Numbers (SSN) for residential customers and SSN and/or Tax ID number for non-residential customers. Using these identifiers, the Company has reduced the amount of uncollected revenue from those customers who would use an alias to defraud the Company of appropriately billed revenues.
- Account Deposit Policy and Procedure - While the Company did not make any changes in its policy and/or procedures with respect to account deposits, it has become more vigilant in adhering to the stated policies and procedures.
- Sold receivables to third party - In March 2007 Delmarva Power sold $23.6 million in uncollectible debts to Arrow Financial Services. This was a onetime project/effort to improve the collections and has not been repeated since.[25]

The Company also used the following efforts to manage and reduce uncollectibles: Company disconnect/collection process, dunning process, agency referral, and bankruptcy maintenance follow-up.[26]

Q. What are your concerns about allowing the Company to implement the proposed Rider VM?

A. First, although pension and OPEB expense are influenced by market returns and interest rates, the level of these expenses is not wholly beyond management control. The Company's management does exercise influence over the levels of pension, OPEB, and

[24] Delmarva Direct Testimony of J. Mack Wathen, p. 15, lines 2 -20.
[25] Delmarva's response to Data Request PSC-A-24 from Docket No. 09-414.
[26] Delmarva's response to Data Request PSC-A-25 from Docket No. 09-414.

uncollectibles. Providing automatic recovery of these expenses would remove the incentive for the Company to control these costs.

Second, historically, the Company and its shareholders have borne the risk of fluctuation in pension, OPEB, and uncollectible expenses. The mechanism removes the risk from shareholders and places it on the Company's customers. The mechanism provides assurance of cost recovery without simultaneously adjusting the risk component for the return on equity. If the Commission adopts the Company's proposal, a downward adjustment to the Company's return on equity is necessary and appropriate.

Third, the adoption of the Rider VM constitutes an unjustified departure from long-standing test period ratemaking precedent. Rates should be set using a test period ratemaking approach giving a utility the opportunity to, but not a guarantee that it will, earn its allowed rate of return on rate base.

Fourth, Rider VM would reduce the Company's cost containment incentives while at the same time making it more difficult for the Commission and other interested parties to review and analyze the Company's pension, OPEB, and uncollectible expenses.

Q. What is your recommendation regarding Rider VM?

A. I recommend that the Commission reject the Company's proposed Rider VM and continue to use traditional test period ratemaking principles for pension, OPEB, and uncollectible expenses.

<u>Utility Facility Relocation Charge Rider (UFRC)</u>

Q. Please explain the proposed Rider UFRC.

A. According to the Company, Rider UFRC is intended to provide a mechanism to recover costs for the relocation of Company distribution facilities related to projects sponsored by the Delaware Department of Transportation (DDOT) or other state agencies as allowed under Section 315 of Title 26 of the Delaware Code.[27]

Q. Does the Company have a proposed UFRC rate?

A. Yes. The Company recommends setting the initial UFRC at 0.00%.[28]

Q. What are your specific concerns with rider UFRC?

A. Delaware law authorizes the Company to implement such a rider; however, the law also authorizes the Commission to adopt administrative rules to administer the UFRC.[29]

Q. Have administrative rules been established and what do you recommend?

A. Such administrative rules have not yet been established. Therefore, I recommend that the UFRC be removed from this case until those administrative rules can be developed to determine an appropriate UFRC.

Q. Will this harm the Company in any way?

A. No. The Company already has an initial 0.00% UFRC, therefore, it should not be harmed.[30]

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[27] Delmarva Direct Testimony of Joseph Janocha, p. 16, lines 3-8.
[28] Delmarva Direct Testimony of Joseph Janocha, p. 17, line 14. .
[29] Delaware Regulation 26 Del, Admin C. ¶¶315, 315(f).
[30] Delmarva Direct Testimony of Joseph Janocha, p. 18, line 1.

Affiliated Charge Review Outside of a Rate Case

Q. Do you have a recommendation concerning conducting a review of affiliated charges to DPL outside of a rate case?

A. Yes. PHI Service Company's 2009 FERC Form 60, at page 307, for example, shows a total amount billed of $484.2 million, of which approximately $130 million was billed to DPL. The $130 million of 2009 charges from PHI Service Company to DPL include $43.8 million of direct costs and $86.3 million of indirect costs, less a credit of approximately $108,000 for compensation for the use of capital. The affiliated charges to DPL from PHI Service Company are significant and have been growing at a rate that warrants additional review beyond that which can usually be applied in the context of a general rate case. Moreover, to conduct such a review, it may be necessary to spend time reviewing documents and interviewing PHI Service Company personnel at the Service Company's offices. Because of time constraints and other factors in a general rate case, Staff was not able to review affiliated service company charges in as much detail as is warranted by the magnitude of such charges. It is difficult to perform an adequate review of such affiliated charges in the context of a rate case because of the relatively short time frame and the need to also address other issues. Consequently, I recommend that Staff perform a detailed review of affiliated charges to DPL, including charges from PHI Service Company, outside of the context of a DPL rate case, such that the results of such review would be available for use in DPL's next rate case. I note that a similar recommendation was made by Staff in DPL's recent electric distribution rate case in Docket No. 09-414, and has been adopted in the Hearing Examiner's recommended decision in that case.

Q. Does this complete your testimony?

A. Yes, it does.

Appendix A

QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)

80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)

R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)

R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)

GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)

Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)

U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)

03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
Docket No. 09-0319	Illinois-American Water Company (Illinois Commerce Commission)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-0872-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)

Delmarva Power & Light Company
Docket No. 10-237
Appendix B
Accompanying the Direct Testimony of Ralph Smith

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-1
Page 1 of 2

Revenue Requirement

Line No.	Description	Reference	Per Company (A)	Per Staff (B)	Difference (C)
1	Adjusted rate base	Sch RCS-3	$ 250,588,453	$ 233,733,292	$ (16,855,161)
2	Rate of return	Sch RCS-5	8.04%	6.55%	
3	Net operating income required		$ 20,147,312	$ 15,316,671	$ (4,830,641)
4	Adjusted net operating income	Sch RCS-4	$ 13,310,182	$ 15,709,575	$ 2,399,393
5	Net operating income deficiency		$ 6,837,130	$ (392,904)	$ (7,230,034)
6	Gross revenue conversion factor	Sch RCS-2	1.69013	1.69013	
7	Revenue deficiency (Sufficiency)		$ 11,555,667	$ (664,061)	$ (12,219,728)
8	Difference (Rounding)		$ (29)		$ (29)
9	Revenue increase		$ 11,555,638	$ (664,061)	$ (12,219,699)

Notes and Source
Col.A: DPL's 12+0 update filing
Col.B & C: See referenced schedules

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-1
Page 2 of 2

Revenue Requirement Reconciliation

Line No.	Description	Appendix B Schedule Reference	Component	Staff Adjustments	Staff Multiplier	Staff Revenue Requirement Amount
				(A)	(B)	(C)
1		RCS-5	ROR Difference		-1.4886%	
2	**Rate Base**	RCS-2	GRCF		x 1.690134	
3	Rate Base per DPL's 12+0 Update Filing	RCS-3		$ 250,588,453	-2.516%	$ (6,304,475)
4		RCS-5	Rate of Return		6.55%	
5	**Effect of Staff Adjustments to Rate Base**	RCS-2	GRCF		x 1.690134	
				Sch RCS-3		
6	Pension Regulatory Asset	RCS-6		$ (2,184,341)	11.08%	$ (241,928)
7	Unamortized Regulatory Commission Expense	RCS-7		$ (333,321)	11.08%	$ (36,917)
8	Construction Work in Progress	RCS-8		$ (2,446,313)	11.08%	$ (270,942)
9	Cash Working Capital	RCS-9		$ 74,319	11.08%	$ 8,231
10	Reverse DPL's AMI Related Pro Forma Adjustments	RCS-10		$ (11,507,547)	11.08%	$ (1,274,523)
11	AMI Deferred Costs	RCS-11		$ (457,958)	11.08%	$ (50,721)
12	Total Staff Rate Base Adjustments			$ (16,855,161)		
13	**Staff Adjusted Original Cost Rate Base**	RCS-3		$ 233,733,292		
	Net Operating Income		Pre-Tax Operating Income Amount	NOI Amount Sch RCS-4	Staff GRCF Sch. RCS-2	
	Effect of Staff Adjustments on NOI					
14	Amortization of Pension Regulatory Asset	RCS-12	$ 817,944	$ 485,409	1.690134	$ (820,406)
15	Normalized Pension Expense	RCS-13	$ 1,231,938	$ 731,093	1.690134	$ (1,235,646)
16	Regulatory Commission Expense	RCS-14	$ 56,167	$ 33,332	1.690134	$ (56,336)
17	Wage and Salary Expense	RCS-15	$ 436,448	$ 259,010	1.690134	$ (437,762)
18	Payroll Tax Expense	RCS-16	$ 33,388	$ 19,814	1.690134	$ (33,488)
19	Non-Executive Incentive Compensation Expense	RCS-17	$ 935,045	$ 554,903	1.690134	$ (937,860)
20	Executive Compensation Expense	RCS-18	$ 18,853	$ 11,188	1.690134	$ (18,910)
21	Stock-Based Compensation Expense	RCS-19	$ 168,630	$ 100,073	1.690134	$ (169,137)
22	Supplemental Executive Retirement Plan	RCS-20	$ 190,184	$ 112,865	1.690134	$ (190,756)
23	Allowance For Funds Used During Construction	RCS-21	$ -	$ (13,522)	1.690134	$ 22,854
24	Interest Synchronization	RCS-22	$ -	$ (339,154)	1.690134	$ 573,216
25	Membership and Industry Association Dues	RCS-23	$ 45,721	$ 27,133	1.690134	$ (45,858)
26	Employee Benefits	RCS-24	$ 315,158	$ 187,030	1.690134	$ (316,106)
27	Reverse DPL's AMI Related Pro Forma Adjustments	RCS-25	$ 195,928	$ 127,777	1.690134	$ (215,961)
28	AMI Deferred Costs	RCS-26	$ 53,220	$ 31,584	1.690134	$ (53,380)
29	Gas Decoupling Customer Education Expense	RCS-27	$ 106,500	$ 63,202	1.690134	$ (106,820)
30	Normalized Meals and Entertainment Expense	RCS-28	$ 12,900	$ 7,656	1.690134	$ (12,939)
31	Total Staff Adjustments to Operating Income	RCS-4	$ 4,618,024	$ 2,399,393		
32	Net Operating Income per Company Filing	RCS-4		$ 13,310,182		
33	**Staff Adjusted Net Operating Income**	RCS-4		$ 15,709,575		
	Gross Revenue Conversion Factor Difference:					
34	Per Staff	RCS-2			1.690134	
35	Per Company	RCS-2			1.690134	
36	Difference				0.000000	
37	Company Adjusted NOI Deficiency	RCS-1			$6,837,130	
38	GRCF Difference					$ -
39	STAFF REVENUE REQUIREMENT ADJUSTMENTS ABOVE					$ (12,226,570)
40	Company Requested Base Rate Revenue Increase	RCS-1				$ 11,555,638
41	Reconciled Revenue Requirement					$ (670,932)
42	Revenue Requirement Calculated on Schedule RCS-1	RCS-1				$ (664,061)
43	Unidentified Difference (Rounding)					$ (6,871)

Notes and Source

Pre-tax return computed using Gross Revenue Conversion Factor

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-2

Gross Revenue Conversion Factor

Line No.	Description	Company Proposed (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00%
	Less:		
2	Regulatory Tax	0.30%	0.30%
3	State Taxable Income	99.70%	99.70%
4	Less: State Income Taxes	8.7%	8.674%
5	Federal Taxable Income	91.026%	91.03%
6	Federal Income Tax - 35%	31.859%	31.859%
7	Change in Net Operating Income	59.167%	59.167%
8	**Gross Revenue Conversion Factor**	**1.69013**	**1.69013**

Notes and Source
Col.A: Delmarva filing, Schedule No. 5

Components of Revenue Requirement Increase

Line No.	Description	Amount	Percent
9	Net Income	$ (392,904)	59.17%
10	Federal Income Taxes	$ (57,601)	8.67%
11	State Income Taxes	$ (211,564)	31.86%
12	Regulatory Tax	$ (1,992)	0.30%
13	Total Revenue Increase	$ (664,061)	100.00%
14	Total Revenue Increase (From Schedule RCS-1, page 1)	$ (664,061)	

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-3
Page 1 of 2

Adjusted Rate Base

Line No.	Description	Company Proposed (A)	Staff Adjustments (B)	Staff Proposed (C)
1	Gas Plant in Service	$ 432,067,165	$ (7,793,900)	$ 424,273,265
2	Intangible Assets	$ 2,290,546	$ -	$ 2,290,546
3	Accumulated Depreciation	$ (171,800,260)	$ (892,470)	$ (172,692,730)
4	**Net Plant in Service**	$ 262,557,451	$ (8,686,370)	$ 253,871,081
	Less:			
5	Customer Advances	$ (219,033)	$ -	$ (219,033)
6	Accumulated Deferred Income Taxes	$ (60,867,389)	$ 2,184,056	$ (58,683,333)
7	Accumulated Investment Tax Credit	$ (658,966)	$ -	$ (658,966)
8	**Total Deductions From Rate Base**	$ (61,745,388)	$ 2,184,056	$ (59,561,332)
	Add:			
9	Materials and Supplies	$ 17,894,347	$ -	$ 17,894,347
10	Working Capital	$ 22,181,758	$ 74,319	$ 22,256,077
11	Construction Work in Progress	$ 2,196,480	$ (2,196,480)	$ -
12	Customer Deposits	$ (4,085,044)	$ -	$ (4,085,044)
13	Amortizable Balances	$ 11,588,849	$ (8,230,686)	$ 3,358,163
14	**Total Additions to Rate Base**	$ 49,776,390	$ (10,352,847)	$ 39,423,543
15	**Total Adjusted Rate Base**	$ 250,588,453	$ (16,855,161)	$ 233,733,292

Notes and Source
Col.A: DPL's 12+0 update filing
Col.B: Schedule RCS-3, page 2

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-3
Page 2 of 2

Adjusted Rate Base - Summary of Adjustments

Line No.	Description	Staff Adjustments	Pension Regulatory Asset RB-1	Unamortized Regulatory Commission Expense RB-2	Construction Work in Progress RB-3	Cash Working Capital RB-4	Reverse DPL's AMI Related Pro Forma Adjustments RB-5	AMI Deferred Costs RB-6
1	Gas Plant in Service	$ (7,793,900)					$ (7,793,900)	
2	Intangible Assets	$ -						
3	Accumulated Depreciation	$ (892,470)					$ (892,470)	
4	**Net Plant in Service**	$ (8,686,370)	$ -	$ -	$ -	$ -	$ (8,686,370)	$ -
	Less:							
5	Customer Advances	$ -						
6	Accumulated Deferred Income Taxes	$ 2,184,056	$ 1,496,409	$ 228,346			$ 145,571	$ 313,730
7	Accumulated Investment Tax Credit	$ -						
8	**Total Deductions From Rate Base**	$ 2,184,056	$ 1,496,409	$ 228,346	$ -	$ -	$ 145,571	$ 313,730
	Add:							
9	Materials and Supplies	$ -						
10	Working Capital	$ 74,319				$ 74,319		
11	Construction Work in Progress	$ (2,196,480)			$ (2,446,313)		$ 249,833	
12	Customer Deposits	$ -						
13	Amortizable Balances	$ (8,230,686)	$ (3,680,750)	$ (561,667)			$ (3,216,581)	$ (771,688)
14	**Total Additions to Rate Base**	$ (10,352,847)	$ (3,680,750)	$ (561,667)	$ (2,446,313)	$ 74,319	$ (2,966,748)	$ (771,688)
15	**Total Adjusted Rate Base**	$ (16,855,161)	$ (2,184,341)	$ (333,321)	$ (2,446,313)	$ 74,319	$ (11,507,547)	$ (457,958)

Notes and Source
See referenced schedule for each adjustment

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-4
Page 1 of 4

Adjusted Net Operating Income

Line No.	Description	Per Company (A)	Staff Adjustments (B)	Per Staff (C)
	Operating Revenues			
1	Sales	$ 66,272,049	$ -	$ 66,272,049
2	Other Revenues	$ 1,353,784	$ -	$ 1,353,784
3	**Total Operating Revenues**	$ 67,625,833	$ -	$ 67,625,833
	Operating Expenses			
4	Operation and Maintenance Expense	$ 32,840,528	$ (2,549,771)	$ 30,290,757
5	Depreciation and Amortization	$ 12,970,632	$ (2,034,865)	$ 10,935,767
6	Taxes Other Than Income	$ 4,115,436	$ (33,388)	$ 4,082,048
7	Income Taxes and Provisions	$ 4,376,819	$ 2,216,613	$ 6,593,432
8	Total Operating Expenses	$ 54,303,415	$ (2,401,411)	$ 51,902,004
9	**Operating Income**	$ 13,322,419	$ 2,401,411	$ 15,723,830
10	AFUDC	$ 2,018	$ (2,018)	$ -
11	Other Income and Deductions	$ (14,255)		$ (14,255)
12	**Net Operating Income**	$ 13,310,182	$ 2,399,393	$ 15,709,575
13	Rate Base	$ 250,588,453	$ (16,855,161)	$ 233,733,292
14	Earned Rate of Return	5.32%		6.73%

Notes and Source

Col.A: DPL's 12+0 update filing
Col.B: See Schedule RCS-4, pages 2-4
Col.C: Col. A + Col. B

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-4
Page 2 of 4

Net Operating Income - Summary of Adjustments

Line No.	Description	Staff Adjustments	Amortization of Pension Regulatory Asset NOI-1	Normalized Pension Expense NOI-2	Regulatory Commission Expense NOI-3	Wage and Salary Expense NOI-4	Payroll Tax Expense NOI-5
	Operating Revenues						
1	Sales	$ -					
2	Other Revenues	$ -					
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
4	Operation and Maintenance Expense	$ (2,549,771)		$ (1,231,938)	$ (56,167)	$ (436,448)	
5	Depreciation and Amortization	$ (2,034,865)	$ (817,944)				
6	Taxes Other Than Income	$ (33,388)					$ (33,388)
7	Other Income and Deductions	$ -					
8	PRE-TAX OPERATING EXPENSES	$ (4,618,024)	$ (817,944)	$ (1,231,938)	$ (56,167)	$ (436,448)	$ (33,388)
9	PRE-TAX OPERATING INCOME	$ 4,618,024	$ 817,944	$ 1,231,938	$ 56,167	$ 436,448	$ 33,388
10	State Income Taxes	$ 474,348	$ 71,161	$ 107,179	$ 4,887	$ 37,971	$ 2,905
11	Federal Income Taxes	$ 1,742,265	$ 261,374	$ 393,666	$ 17,948	$ 139,467	$ 10,669
12	Federal & State Income Taxes	$ 2,216,613	$ 332,535	$ 500,845	$ 22,835	$ 177,438	$ 13,574
13	TOTAL OPERATING EXPENSES	$ (2,401,411)	$ (485,409)	$ (731,093)	$ (33,332)	$ (259,010)	$ (19,814)
14	AFUDC	$ (2,018)					
15	OPERATING INCOME	$ 2,399,393	$ 485,409	$ 731,093	$ 33,332	$ 259,010	$ 19,814

Notes and Source

Line 10: State Income Tax Rate	8.70%
Line 11: Federal Income Tax Rate	35.00%

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-4
Page 3 of 4

Net Operating Income - Summary of Adjustments

Line No.	Description	Non-Executive Incentive Compensation Expense NOI-6	Executive Compensation Expense NOI-7	Stock-Based Compensation Expense NOI-8	Supplemental Executive Retirement Plan NOI-9	Allowance For Funds Used During Construction NOI-10	Interest Synchronization NOI-11	Membership and Industry Association Dues NOI-12
	Operating Revenues							
1	Sales							
2	Other Revenues							
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Operation and Maintenance Expense	$ (935,045)	$ (18,853)	$ (168,630)	$ (190,184)			$ (45,721)
5	Depreciation and Amortization							
6	Taxes Other Than Income							
7	Other Income and Deductions							
8	PRE-TAX OPERATING EXPENSES	$ (935,045)	$ (18,853)	$ (168,630)	$ (190,184)	$ -	$ -	$ (45,721)
9	PRE-TAX OPERATING INCOME	$ 935,045	$ 18,853	$ 168,630	$ 190,184	$ -	$ -	$ 45,721
10	State Income Taxes	$ 81,349	$ 1,640	$ 14,671	$ 16,546	$ -	$ 72,578	$ 3,978
11	Federal Income Taxes	$ 298,794	$ 6,025	$ 53,886	$ 60,773	$ -	$ 266,576	$ 14,610
12	Federal & State Income Taxes	$ 380,143	$ 7,665	$ 68,557	$ 77,319	$ -	$ 339,154	$ 18,588
13	TOTAL OPERATING EXPENSES	$ (554,903)	$ (11,188)	$ (100,073)	$ (112,865)	$ -	$ 339,154	$ (27,133)
14	AFUDC					$ (13,522)		
15	OPERATING INCOME	$ 554,903	$ 11,188	$ 100,073	$ 112,865	$ (13,522)	$ (339,154)	$ 27,133

Notes and Source
Line 10: State Income Tax Rate
Line 11: Federal Income Tax Rate

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-4
Page 4 of 4

Net Operating Income - Summary of Adjustments

Line No.	Description	Employee Benefits	Reverse DPL's AMI Related Pro Forma Adjustments	AMI Deferred Costs	Gas Decoupling Customer Education Expense	Normalized Meals and Entertainment Expense
		NOI-13	NOI-14	NOI-15	NOI-16	NOI-17
	Operating Revenues					
1	Sales					
2	Other Revenues					
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -
4	Operation and Maintenance Expense	$ (315,158)	$ 967,773		$ (106,500)	$ (12,900)
5	Depreciation and Amortization		$ (1,163,701)	$ (53,220)		
6	Taxes Other Than Income					
7	Other Income and Deductions					
8	PRE-TAX OPERATING EXPENSES	$ (315,158)	$ (195,928)	$ (53,220)	$ (106,500)	$ (12,900)
9	PRE-TAX OPERATING INCOME	$ 315,158	$ 195,928	$ 53,220	$ 106,500	$ 12,900
10	State Income Taxes	$ 27,419	$ 17,046	$ 4,630	$ 9,266	$ 1,122
11	Federal Income Taxes	$ 100,709	$ 62,609	$ 17,007	$ 34,032	$ 4,122
12	Federal & State Income Taxes	$ 128,128	$ 79,655	$ 21,637	$ 43,298	$ 5,244
13	TOTAL OPERATING EXPENSES	$ (187,030)	$ (116,273)	$ (31,584)	$ (63,202)	$ (7,656)
14	AFUDC		$ 11,504			
15	OPERATING INCOME	$ 187,030	$ 127,777	$ 31,584	$ 63,202	$ 7,656

Notes and Source
Line 10: State Income Tax Rate
Line 11: Federal Income Tax Rate

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-5
Page 1 of 1

Capital Structure and Cost of Capital

Line No.	Description	Capital Structure Ratio	Cost Rate	**Weighted Cost** (A) x (B)
		(A)	(B)	(C)
	I. Per Company			
1	Long-Term Debt	51.72%	5.28%	2.73%
2	Common Equity	48.28%	11.00%	5.31%
3	Total	100.00%		8.04%
	II. Per Staff			
4	Long-Term Debt	51.72%	4.97%	2.57%
5	Common Equity	48.28%	9.25%	
6	Adjustment for Decoupling		-1.00%	
7	Adjusted Common Equity		8.25%	3.98%
8	Total	100.00%		6.55%
9	Difference	L8 - L3		-1.49%
10	Weighted Cost of Debt	Line 4		2.57%

Notes

Lines 1-3: Schedule FJH-21 from DPL's 12+0 filing
Lines 4-8: Per Staff witness James Rothschild

Delmarva Power & Light Company
Test Period Ended June 30, 2010

RB-1, Pension Regulatory Asset

Line No.	Description	Amount (A)	Reference
1	Reverse Company Adjustment to Amortizable Balances Related to Pension Regulatory Asset	$ (3,680,750)	A
2	Reverse Corresponding Company Adjustment to Accumulated Deferred Income Taxes	$ 1,496,409	A
3	Net Adjustment to Rate Base Related to Pension Regulatory Asset	$ (2,184,341)	

Notes and Source

A: Per Schedule JCZ-15 (Adjustment No. 27) from DPL's 12+0 update filing

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-7
Page 1 of 1

RB-2, Unamortized Regulatory Commission Expense

Line No.	Description	Amount (A)	Reference
1	Reverse Company Adjustment to Amortizable Balances Related to Regulatory Commission Expense	$ (561,667)	A
2	Reverse Corresponding Company Adjustment to Accumulated Deferred Income Taxes	$ 228,346	A
3	Net Adjustment to Rate Base Related to Unamortized Regulatory Commission Expense	$ (333,321)	

Notes and Source

A: Per Schedule WMV-4 (Adjustment No. 2) from DPL's 12+0 update filing

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-8
Page 1 of 1

RB-3, Construction Work in Progress

Line No.	Description	Amount	Reference
1	Remove CWIP from Rate Base	$ (2,446,313)	A

Notes and Source

A: Amount from DPL's combined 12+0 and AMI related update filings (calculated below)

		Amount	Reference
2	DPL Pro Forma CWIP per 12+0 update filing	$ 2,196,480	($4,697,990 - $2,251,677 - $249,833)
3	CWIP related to AMI net plant additions	$ 249,833	Schedule JCZ-7 (Adjustment No. 19) from 12+0 update filing*
4	Total CWIP removed from rate base	$ 2,446,313	

* This amount reversed on Staff Schedule RCS-10

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-9
Page 1 of 1

RB-4, Cash Working Capital

Line No.	Description	Amount (A)	Staff Adjustment (B)	Staff Adjusted (C)	Revenue Lag (D)	Exp Lag (E)	Net lag (F)	Net lag % (G)	CWC Req (H)
	O & M Expense								
1	Purchased Fuel	$ 168,346,278		$ 168,346,278	60.08	40.59	19.49	5.340%	$ 8,989,230
2	Deferred Fuel	$ (12,493,289)		$ (12,493,289)	60.08	60.08	0.00	0.000%	$ -
3	Other Production	$ 2,173,711		$ 2,173,711	60.08	28.28	31.80	8.712%	$ 189,381
4	Transmission	$ 1,906,380		$ 1,906,380	60.08	28.28	31.80	8.712%	$ 166,090
5	Distribution	$ 10,617,310		$ 10,617,310	60.08	28.28	31.80	8.712%	$ 925,015
6	Other O&M	$ 17,727,469	$ (3,367,715)	$ 14,359,754	60.08	28.28	31.80	8.712%	$ 1,251,069
7	Total O & M Expense	$ 188,277,859	$ (3,367,715)	$ 184,910,144					$ 11,520,785
	Other								
8	Utility Taxes	$ 2,613,838		$ 2,613,838	60.08	35.20	24.88	6.816%	$ 178,171
9	FICA	$ 373,836	$ (33,388)	$ 340,448	60.08	11.91	48.17	13.197%	$ 44,930
10	Federal Unemployment	$ 7,708		$ 7,708	60.08	76.38	-16.30	-4.466%	$ (344)
11	State Unemployment	$ 16,288		$ 16,288	60.08	76.38	-16.30	-4.466%	$ (727)
12	Property Taxes	$ 3,670,820		$ 3,670,820	60.08	(90.50)	150.58	41.255%	$ 1,514,389
13	SIT	$ (1,728,310)	$ 1,284,582	$ (443,728)	60.08	(17.30)	77.38	21.200%	$ (94,070)
14	FIT	$ (891,837)	$ 662,866	$ (228,971)	60.08	37.00	23.08	6.323%	$ (14,478)
15	Interest Expense	$ 6,706,920	$ (700,080)	$ 6,006,840	60.08	90.26	-30.18	-8.268%	$ (496,675)
16	IOCD	$ 38,676		$ 38,676	60.08	182.50	-122.42	-33.540%	$ (12,972)
17	Preferred Dividends	$ -		$ -	60.08	45.63	14.45	3.959%	$ -
18	Total Other	$ 10,807,939	$ 1,213,980	$ 12,021,919					$ 1,118,222
19	Total Per Staff	$199,085,798	($2,153,735)	$196,932,063					$ 12,639,007
20	Cash Working Capital Requirement Per DPL's 12+0 update filing								$ 12,564,688
21	Adjustment to Cash Working Capital								$ 74,319

Notes and Source

Cols. A-H per Workpaper No. 9 from DPL's 12+0 update filing

Lines 13 & 14, Col. C, Current Federal and State Income Taxes	Amount	Percentage
Per DPL, Current State Income Taxes (Col. A, line 13)	$ (1,728,310)	65.96%
Per DPL, Current Federal Income Taxes (Col. A, line 14)	$ (891,837)	34.04%
Total Income Taxes Before Revenue Increase	$ (2,620,147)	100.00%
Staff adjustments to current Income Taxes	$ 2,216,613	Schedule RCS-4, page 2, line 12
Staff adjusted Income Taxes before revenue increase	$ (403,534)	
Income Taxes for revenue increase	$ (269,165)	Schedule RCS-2, lines 10+11
Total current Income Taxes for CWC calculation	$ (672,699)	Allocated to Federal and State Income Taxes based on the percentages above

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-10
Page 1 of 1

RB-5, Remove AMI Related Costs From Rate Base

Line No.	Description	Amount (A)	Reference
1	Gas Plant in Service	$ (7,793,900)	L11 + L19
2	Accumulated Depreciation	$ (892,470)	L15+ L20
3	Net Plant	$ (8,686,370)	
4	CWIP	$ 249,833	L16
5	Accumulated Deferred Income Taxes	$ 145,571	L17 + L25
6	Stranded Costs	$ (3,216,581)	L22
7	Net Adjustment to Rate Base	$ (11,507,547)	

Notes and Source

Col. A: Amounts reflect the net impact of reversing DPL's proposed adjustments related to AMI costs per its 12+0 update filing

	Schedule JCZ-7 (Adjustment No. 19)	Amount
	Pro Forma Plant in Service	
8	Delmarva Power - IMU	$ (9,642,913)
9	Delmarva Power - Communication Equipment	$ (289,305)
10	Service Company - IT Hardware and Software	$ (2,614,567)
11	Adjustment to Plant in Service	$ (12,546,785)
	Accumulated Depreciation	
12	Delmarva Power - IMU	$ 200,692
13	Delmarva Power - Communication Equipment	$ 7,918
14	Service Company - IT Hardware and Software	$ 250,273
15	Adjustment to Accumulated Depreciation	$ 458,883
16	Construction Work in Progress	$ 249,833
17	Accumulated Deferred Income Taxes	$ 220,763
18	Total Rate Base	$ (11,617,306)
	Schedule JCZ-8 (Adjustment No. 20)	
19	Plant in Service	$ 4,752,885
20	Accumulated Depreciation	$ (1,351,353)
21	Total Plant	$ 3,401,532
22	Stranded Costs	$ (3,216,581)
23	Accumulated Deferred State Income Taxes	$ (16,091)
24	Accumulated Deferred Federal Income Taxes	$ (59,101)
25	Total Accumulated Deferred Income Taxes	$ (75,192)
26	Total Rate Base	$ 109,759

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-11
Page 1 of 1

RB-6, AMI Deferred Costs

Line No.	Description	Schedule JCZ-9 AMI Supplemental Filing	Schedule JCZ-9 12+0 Update Filing	Adjustment
		(A)	(B)	(C)
1	Average Amortizable Balance	$ 1,022,279	$ 1,793,967	$ (771,688)
2	Deferred State Income Tax	$ (88,938)	$ (156,075)	
3	Deferred Federal Income Tax	$ (326,669)	$ (573,262)	
4	Total Deferred Income Tax	$ (415,607)	$ (729,337)	$ 313,730
5	Net Rate Base	$ 606,672	$ 1,064,630	$ (457,958)

Notes and Source

Cols. A&B: As noted, these columms reflect AMI related data from DPL's 12+0 Update and AMI supplemental filings

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-12
Page 1 of 1

NOI-1, Amortization of Pension Regulatory Asset

Line No.	Description	Amount (A)	Reference
1	Reverse Company Adjustment to Amortize Pension Regulatory Asset	$ (817,944)	A

Notes and Source

A: Per Schedule JCZ-15 (Adjustment No. 27) from DPL's 12+0 update filing

Delmarva Power & Light Company
Adjustment to Normalize Pension Expense

Docket No. 10-237
Schedule RCS-13
Page 1 of 1

NOI-2, Normalized Pension Expense For Ratemaking Purposes

Line No.	Description	Amount (A)	Reference
1	Pro Forma Pension Expense Per Company	$ 3,166,916	A
2	Staff Recommended Pro Forma Pension Expense	$ 1,934,978	B
3	Adjustment to Normalize Pension Expense	$ (1,231,938)	L2 - L1

Notes and Source

A: Per Schedule JCZ-4 (Adjustment No. 11) from DPL's 12+0 update filing

B: Staff recommended pro forma pension expense calculated as follows:

		Amount	
4	2008 Pension Expense	$ (42,423)	per PSC-2-6 from Docket No. 09-182
5	2009 Pension Expense	$ 3,912,379	per Schedule JCZ-15 (Adjustment No. 27)
6	Subtotal	$ 3,869,956	
7	Normalized over two years	2	
8	Staff recommended normalized pension expense	$ 1,934,978	

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-14
Page 1 of 1

NOI-3, Regulatory Commission Expense

Line No.	Description		Amount (A)	Reference
1	Normalized Regulatory Commission Expense Per Company	$	339,505	A
2	Staff Recommended Normalized Regulatory Commission Expense	$	283,338	B
3	Staff Adjustment to Regulatory Commission Expense	$	(56,167)	L2 - L1

Notes and Source

A: Per Schedule WMV-4 (Adjustment No. 2) from DPL's 12+0 update filing and calculated as follows:

				Amount	
4	Three-year average Regulatory Commission Expense		$	64,838	
5	Cost related to DPA charging non-base activities		$	50,000	
	DPL's estimate of the costs of the current proceeding				
6	External legal		$	300,000	
7	Cost of capital consultant		$	49,000	
8	Court reporter/notice/etc.		$	25,000	
9	DPSC		$	200,000	
10	DPA		$	100,000	
11		Subtotal	$	674,000	
12	Amortized over three years			3	
13	Current case costs amortized over three years per Company		$	224,667	
14	Total pro forma Regulatory Commission Expense per Company		$	339,505	L4 + L5 + L13

B: Staff recommended regulatory commission expense calculated as follows:

				Amount	
15	Three-year average Regulatory Commission Expense		$	64,838	
16	Cost related to DPA charging non-base activities		$	50,000	
	Current proceeding costs				
17	External legal		$	300,000	
18	Cost of capital consultant		$	49,000	
19	Court reporter/notice/etc.		$	25,000	
20	DPSC		$	200,000	
21	DPA		$	100,000	
22		Subtotal	$	674,000	
23	Normalized over four years			4	
24	Current case costs normalized over four years per Staff		$	168,500	
25	Total pro forma Regulatory Commission Expense per Staff		$	283,338	L15 + L16 + L24

NOI-4, Wages and Salary Expense

Line No.	Description	Amount (A)	Reference
1	Total Company Pro Forma Wage and Salary Expense Per Company	$ 126,685,220	A
2	Staff Recommended Total Company Pro Forma Wage and Salary Expense	$ 124,388,124	B
3	Adjustment to Total Company Pro Forma Wage and Salary Expense	$ (2,297,096)	
4	Gas Expense Ratio	19%	A
5	Adjustment to Wage and Salary Expense Allocated to DPL's Gas Operations	$ (436,448)	

Notes and Source

A: Amount per electronic version of Schedule WMV-5 (Adjustment No. 3) from DPL's 12+0 update filing

B: See page 2 of Schedule RCS-15

Delmarva Power & Light Company
Test Period Ended June 30, 2010

NOI-4, Wages and Salary Expense

Docket No. 10-237
Schedule RCS-15
Page 2 of 2

Delaware - Gas
12 Months Ending June 30, 2010

Line No.	Month	Rate (A)	Local 1238 Level (B)	Remove AMI-related Costs (C)	Local 1238 Adjusted (D)	Rate (E)	Local 1307 Level (F)	Rate (G)	Non-Union Level (H)	Total (I)	12 Month Total (J)
	Wage & Salary Adjustment										
1	July 09		$ 2,457,372	$ (70,466)	$ 2,386,906		$ 1,118,192		$ 7,184,270	$ 10,759,834	
2	August 09		$ 2,310,727	$ (56,959)	$ 2,253,768		$ 1,051,463		$ 6,755,544	$ 10,117,734	
3	September 09		$ 2,206,398	$ (55,710)	$ 2,150,688		$ 1,003,990		$ 6,450,532	$ 9,660,920	
4	October 09		$ 2,156,347	$ (73,956)	$ 2,082,391		$ 981,215		$ 6,304,206	$ 9,441,768	
5	November 09		$ 2,317,209	$ (60,053)	$ 2,257,156		$ 1,054,413		$ 6,774,494	$ 10,146,116	
6	December 09		$ 2,239,710	$ (60,021)	$ 2,179,689		$ 1,019,148		$ 6,547,920	$ 9,806,778	
7	January 10		$ 2,422,387	$ (52,949)	$ 2,369,438		$ 1,102,272		$ 7,081,987	$ 10,606,646	
8	February 10		$ 2,335,196	$ (52,949)	$ 2,282,247		$ 1,062,597		$ 6,827,082	$ 10,224,876	
9	March 10		$ 2,248,971	$ (52,949)	$ 2,196,022		$ 1,023,362		$ 6,574,996	$ 9,847,328	
10	April 10		$ 2,456,602	$ (52,949)	$ 2,403,653		$ 1,117,841		$ 7,182,018	$ 10,756,462	
11	May 10		$ 2,314,500	$ (52,949)	$ 2,261,551		$ 1,053,180		$ 6,766,575	$ 10,134,256	
12	June 10		$ 2,562,620	$ (52,949)	$ 2,509,671		$ 1,166,083		$ 7,491,970	$ 11,220,674	$ 122,723,391
	Staff Recommended Pro Forma Wage and Salary Expense										
13	July 10	0.00%			$ 2,386,906	0.00%	$ 1,118,192	3.09%	$ 7,406,264	$ 10,911,362	
14	August 10	0.00%			$ 2,253,768	0.00%	$ 1,051,463	3.09%	$ 6,964,290	$ 10,269,521	
15	September 10	0.00%			$ 2,150,688	0.00%	$ 1,003,990	3.09%	$ 6,649,853	$ 9,804,531	
16	October 10	0.00%			$ 2,082,391	0.00%	$ 981,215	3.09%	$ 6,499,006	$ 9,562,612	
17	November 10	0.00%			$ 2,257,156	0.00%	$ 1,054,413	3.09%	$ 6,983,826	$ 10,295,395	
18	December 10	0.00%			$ 2,179,689	0.00%	$ 1,019,148	3.09%	$ 6,750,251	$ 9,949,088	
19	January 11	0.00%			$ 2,369,438	0.00%	$ 1,102,272	3.09%	$ 7,300,820	$ 10,772,530	
20	February 11	2.00%			$ 2,327,892	0.00%	$ 1,062,597	3.09%	$ 7,038,039	$ 10,428,529	
21	March 11	2.00%			$ 2,239,942	0.00%	$ 1,023,362	0.00%	$ 6,574,996	$ 9,838,300	
22	April 11	2.00%			$ 2,451,727	0.00%	$ 1,117,841	0.00%	$ 7,182,018	$ 10,751,586	
23	May 11	2.00%			$ 2,306,782	0.00%	$ 1,053,180	0.00%	$ 6,766,575	$ 10,126,538	
24	June 11	2.00%			$ 2,559,865	0.00%	$ 1,166,083	0.00%	$ 7,491,970	$ 11,217,918	
25	July 11	2.00%			$ 2,434,644	2.00%	$ 1,140,556	0.00%	$ 7,406,264	$ 10,981,464	
26	August 11	2.00%			$ 2,298,843	2.00%	$ 1,072,492	0.00%	$ 6,964,290	$ 10,335,626	
27	September 11	2.00%			$ 2,193,702	2.00%	$ 1,024,070	0.00%	$ 6,649,853	$ 9,867,625	
28	October 11	2.00%			$ 2,124,039	2.00%	$ 1,000,839	0.00%	$ 6,499,006	$ 9,623,884	
29	November 11	2.00%			$ 2,302,299	2.00%	$ 1,075,501	0.00%	$ 6,983,826	$ 10,361,626	
30	December 11	2.00%			$ 2,223,283	2.00%	$ 1,039,531	0.00%	$ 6,750,251	$ 10,013,064	
31	January 12	2.00%			$ 2,416,827	2.00%	$ 1,124,317	0.00%	$ 7,300,820	$ 10,841,964	$ 124,388,124

Notes and Source

Amounts in columns A through J from the electronic version of Schedule WMV-5 (Adjustment No. 3) from DPL's 12+0 update filing

Delmarva Power & Light Company
Test Period Ended June 30, 2010

NOI-5, Payroll Tax Expense

Docket No. 10-237
Schedule RCS-16
Page 1 of 1

Line No.	Description	Amount (A)	Reference
1	Adjustment to Payroll Tax Expense	$ (33,388)	A

Notes and Source

A: Staff adjustment to payroll tax expense calculated as follows:

Line No.	Description	Amount	Reference
2	Adjustment to Wages and Salary Expense related to Gas operations- see Schedule RCS-15	$ (436,448)	
3	OASDI Rate	6.20%	
4	OASDI Adjustment	$ (27,060)	
5	Adjustment to Wages and Salary Expense related to Gas operations - see Schedule RCS-15	$ (436,448)	
6	Medicare Rate	1.45%	
7	Medicare Adjustment	$ (6,328)	
8	Total Adjustment to payroll tax expense related to DPL's Gas operations	$ (33,388)	L4 + L7

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-17
Page 1 of 1

NOI-6, Non-Executive Incentive Compensation

Line No.	Description	Safety (A)	Non-Safety (B)	Total (C)	Reference
1	Adjustment to Remove Non-Executive Incentive Compensation Expense	$ (85,548)	$ (849,498)	$ (935,045)	A

Notes and Source

A: Amounts per Schedule WMV-7 (Adjustment Nos. 5 & 6) from DPL's 12+0 update filing and calculated as follows:

		Safety	Non-Safety	Total
2	12 months ended December 31, 2007	$ 56,898	$ 942,615	$ 999,513
3	12 months ended December 31, 2008	$ 83,323	$1,180,384	$ 1,263,707
4	12 months ended December 31, 2009	$ 116,422	$ 425,494	$ 541,916
5	3 year average	$ 85,548	$ 849,498	$ 935,045

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-18
Page 1 of 1

NOI-7, Executive Compensation Expense

Line No.	Description	Amount (A)	
1	Dividends Paid on Unvested Shares of Restricted Stock	$ (155,249)	
2	Company Match Deferred Compensation	$ (29,454)	
3	Tax Preparation Fees	$ (15,600)	
4	Financial Planning Fees	$ (60,510)	
5	Club Dues	$ (30,710)	
6	Spousal Travel	$ (8,278)	
7	Employment Transition Expenses	$ (77,779)	
8	Total	$ (377,580)	
9	DPL Allocation Percentage	26.28%	per PSC-LA-92
10	Allocated to DPL	$ (99,228)	
11	Gas Allocation Percentage	19.00%	
12	Adjustment to Remove Executive Compensation Allocated to DPL's Gas Operations	$ (18,853)	

Notes and Source
Col. A: Amounts from PHI's 2009 Proxy Statement calculated as follows:

Line No.	Description	Dividends Restricted Stock (B)	Co. Match Deferred Compensation (C)	Tax Prep Fees (D)	Financial Planning Fees (E)	Club Dues (F)	Spousal Travel (G)	Employment Transition Expense (H)
13	Joseph M. Rigby - Chairman, President and CEO	$ 45,476	$ 15,936	$ 2,400	$ 10,005	$ 5,450	$ 2,926	$ -
14	Anthony J. Kamerick - Senior Vice President and CFO	$ 13,382	$ 1,187	$ 2,400	$ -	$ 1,104	$ -	$ -
15	David M. Velazquez - Executive Vice President	$ 14,717	$ -	$ -	$ 9,175	$ -	$ -	$ 42,820
16	Kirk J. Emge - Senior Vice President and General Counsel	$ 11,410	$ 6,038	$ 2,400	$ 11,315	$ 400	$ 3,832	$ -
17	John U. Huffman - President and CFO - PEPCO Energy Services	$ 12,151	$ 681	$ 2,400	$ 10,005	$ -	$ -	$ -
18	Dennis R. Wraase - Retired Chairman	$ 40,854	$ 5,612	$ 2,400	$ 10,005	$ 13,248	$ 1,520	$ -
19	Paul H. Barry - Retired Senior Vice President and CFO	$ 5,484	$ -	$ 1,200	$ 10,005	$ 1,358	$ -	$ 34,959
20	William T. Torgerson - Retired Vice Chairman and Chief Legal Officer	$ 11,775	$ -	$ 2,400	$ -	$ 9,150	$ -	$ -
21	Total	$ 155,249	$ 29,454	$ 15,600	$ 60,510	$ 30,710	$ 8,278	$ 77,779

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-19
Page 1 of 1

NOI-8, Stock-Based Compensation

Line No.	Description	Adjustment (A)	Reference
1	Adjustment to Remove Stock-Based Compensation Expense	$ (168,630)	A

Notes and Source

A: Amount from DPL's response to PSC-LA-92 and calculated as follows:

		Amount
	DPL	
2	Total DPL Stock Based Compensation Expense	$ 45,112
3	Allocation Percentage of Gas Operations to Total DPL Cost	12.17%
4	Stock Based Compensation Expense Allocated to DPL's Gas Operations	$ 5,492
	Service Company	
5	Total Service Company Stock-Based Compensation Expense	$ 3,925,949
6	Expense Allocation Percentage	83.22%
7	Service Company Stock-Based Compensation Expense Allocated to Expense	$ 3,267,175
8	DPL Allocation Percentage	26.28%
9	Service Company Stock-Based Compensation Expense Allocated to DPL	$ 858,614
10	Gas Allocation Percentage	19.00%
11	Service Company Stock-Based Compensation Expense Allocated to DPL's Gas Operations	$ 163,138
12	Total Adjustment to Remove Stock-Based Compensation Expense	$ 168,630

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-20
Page 1 of 1

NOI-9, Supplemental Executive Retirement Plan Expense

Line No.	Description	Amount (A)	Reference
1	Adjustment to Remove SERP Expense	$ (190,184)	A

Notes and Source

A: Amount from DPL's response to DPA-23 and calculated as follows:

Line No.	Description	July 2009 - December 2009 (B)	January 2010 - June 2010 (C)	Total (D)
	DPL			
2	Total DPL SERP Expense	$ 302,831	$ 329,040	
3	Gas Allocation Percentage	12.28%	12.17%	
4	DPL SERP Expense allocated to Gas operations	$ 37,188	$ 40,044	$ 77,232
	Service Company			
5	Total Service Company SERP Expense	$ 358,538	$ 351,463	
6	Gas Allocation Percentage	19.00%	19.00%	
7	Total SERP allocated to DPL's Gas operations	$ 68,122	$ 66,778	
8	Expense Allocation Percentage	84.23%	83.22%	
9	Service Company SERP Expense allocated to DPL's Gas operations	$ 57,379	$ 55,573	$ 112,952
10	Total SERP Expense allocated to DPL's Gas operations	$ 94,567	$ 95,617	$ 190,184

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-21
Page 1 of 1

NOI-10, Allowance For Funds Used During Construction

Line No.	Description	Amount (A)	Reference
1	Remove Allowance For Funds Used During Construction	$ (13,522)	A

Notes and Source

A: Amount below from DPL's 12+0 update filing

		Amount	
2	Remove DPL Pro Forma AFUDC per 12+0 update filing	$ (2,018)	($66,307 - $52,785 - $11,504)
3	AFUDC adjustment related to AMI net plant additions	$ (11,504)	Schedule JCZ-7 (Adjustment No. 19) from 12+0 update filing*
4	Net Adjustment to AFUDC	$ (13,522)	

* This amount "added back" on Staff Schedule RCS-25

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-22
Page 1 of 1

NOI-11, Interest Synchronization

Line No.	Description	Tax Rate	Amount	Reference
1	Adjusted Rate Base, per Staff		$ 233,733,292	Schedule RCS-3
2	Weighted Cost of Debt, per Staff		2.57%	Schedule RCS-5
3	Interest Deduction for Tax Purposes		$ 6,006,840	L1 x L2
4	Interest Deduction per Company		$ 6,841,065	Note A
5	Decrease in Deductible Interest		$ (834,225)	L3 - L4
6	State Income Taxes	8.7%	$ 72,578	
7	Federal Taxable Income		$ (761,647)	
8	Federal Income Taxes	35.00%	$ 266,576	
9	Increase (Decrease) to Income Tax Expense		$ 339,154	L5 x L6

Notes and Source
A: Company interest deduction per Schedule WMV-16 from DPL's 12+0 update filing

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-23
Page 1 of 2

NOI-12, Membership and Industry Association Dues

Line No.	Description	DPL Filing (A)	Allowance Per Staff (B)	Staff Adjustment (C)
1	American Gas Association	$ 111,052	$ 66,631	$ (44,421)
2	Energy Association of Pennsylvania	$ 1,500	$ 1,500	$ -
3	Gas Professional Association of Memberships	$ 1,300	$ -	$ (1,300)
4	Northeast Gas Association	$ 350	$ 350	$ -
5	Society of Gas Operators	$ 300	$ 300	$ -
6	Total Gas Association Dues	$ 114,502	$ 68,781	$ (45,721)

Notes and Source

Col. A: Amounts from Schedule 3-G from DPL's 6+6 filing

		Amount
7	Test Period American Gas Association Dues	$ 111,052
8	Recommended disallowance per NARUC Audit Categories	40%
9	Staff adjustment	$ 44,421

Delmarva Power & Light Company
Test Period Ended June 30, 2010

NOI-12, Membership and Industry Association Dues

American Gas Association
Schedule of Expenses by NARUC Category

		March 2005 NARUC Audit Report for Year Ended 12/31/02		AGA 2007 Budget			AGA 2008 Budget		
Line No.	NARUC Operating Expense Category	% of Dues	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance	% of Dues	With G&A Allocated	Recommende Disallowance
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Public Affairs	24.13%	24.13%	23.29%	28.67%	28.67%	24.44%	30.63%	30.63%
2	Advertising			1.39%	1.71%	1.71%	1.18%	1.48%	1.48%
3	Communications	15.53%							
4	Corporate Affairs and International	10.54%	10.54%	8.44%	10.39%	10.39%	9.14%	11.46%	11.46%
5	General Counsel & Corp Secretary	5.20%		4.09%	5.04%		4.17%	5.23%	
6	Regulatory Affairs	15.51%							
7	Policy Planning & Regulatory Affairs			14.76%	18.17%		15.78%	19.78%	
8	Marketing Department	2.37%	2.37%						
9	Operating & Engineering Services	15.85%		24.11%	29.68%		21.71%	27.21%	
10	Policy & Analysis	12.94%							
11	Industry Finance & Admin. Programs	4.75%	4.75%	5.16%	6.35%		3.36%	4.21%	
12	General & Administrative			18.77%			20.22%		
13	Total Expenses	106.82%	41.79%	100.01%	100.01%	40.77%	100.00%	100.00%	43.57%
14	Lobbying per IRC Section 162			2%			4%		

Notes and Source
Col.A: March 2005 Annual Audit Report on the Expenditures of the American Gas Association for the 12 month period ended December 31, 2002

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-24
Page 1 of 1

NOI-13, Employee Benefits

Line No.	Description	Amount (A)	Reference
1	Reverse Company Adjustment to Employee Benefits	$ (315,158)	A

Notes and Source
A: Amount per Schedule WMV-8 (Adjustment No. 10) from DPL's 12+0 update filing

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-25
Page 1 of 1

NOI-14, Reverse Company Proposed AMI Adjustments to Net Operating Income

Line No.	Description	Amount (A)	Reference
1	O&M Expense	$ 967,773	Line 12
2	Depreciation and Amortization Expense	$ (1,163,701)	L20 + L30
3	Income Taxes	$ 79,656	L15 + L25 + L33
4	Allowance For Funds Used During Construction	$ 11,504	Line 26
5	Net Impact on Net Operating Income	$ (127,776)	

Notes and Source
Col. A: Amounts reflect the net impact of reversing DPL's proposed adjustments related to AMI costs per its 12+0 update filing

	Schedule JCZ-6 (Adjustment No. 18)	Amount	
	Pro Forma Incremental O&M		
6	Hardware & Software Expenses	$ (241,972)	
7	Meter Related Expenses	$ (90,000)	
8	Total Pro Forma Incremental O&M	$ (331,972)	
9	Elimintated Manual Meter Reading Costs	$ 1,176,069	
10	Reduced Off-Cycle Meter Reading Labor Costs	$ 123,676	
11	Total O&M Reductions	$ 1,299,745	
12	Net O&M Adjustment	$ 967,773	L8 + L11
13	State Income Tax	$ (84,196)	
14	Federal Income Tax	$ (309,252)	
15	Total Income Tax	$ (393,448)	
16	Total Earnings	$ 574,325	L12 + L15
	Schedule JCZ-7 (Adjustment No. 19)	Amount	
	Depreciation Expense		
17	Delmarva Power - IMU	$ (633,778)	
18	Delmarva Power - Communications Equipment	$ (12,722)	
19	Service Company - IT Hardware and Software	$ (507,434)	
20	Adjustment to Depreciation	$ (1,153,934)	
21	State Income Tax	$ 41,947	
22	Federal Income Tax	$ 154,070	
23	Deferred State Income Tax	$ 58,446	
24	Deferred Federal Income Tax	$ 214,670	
25	Total Income Taxes	$ 469,133	
26	Allowance For Funds Used During Construction	$ 11,504	
27	Total Earnings	$ (696,305)	L20 + L25 - L26
	Schedule JCZ-8 (Adjustment No. 20)		
28	Depreciation Expense	$ 204,672	
29	Amortization of Stranded Costs	$ (214,439)	
30	Net Depreciation and Amortization Expense	$ (9,767)	
31	State Income Tax	$ 850	
32	Federal Income Tax	$ 3,121	
33	Total Income Tax	$ 3,971	
34	Total Earnings	$ (5,796)	L30 + L33

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-26
Page 1 of 1

NOI-15, AMI Deferred Costs

Line No.	Description	Schedule JCZ-9 AMI Supplemental Filing (A)	Schedule JCZ-9 12+0 Update Filing (B)	Adjustment (C)
1	Amortization	$ 70,502	$ 123,722	$ (53,220)
2	State Income Tax	$ (6,134)	$ (10,764)	$ 4,630
3	Federal Income Tax	$ (22,529)	$ (39,535)	$ 17,006
4	Total Deferred Income Tax	$ (28,663)	$ (50,299)	$ 21,636
5	Net Adjustment	$ 41,839	$ 73,423	$ (31,584)

Notes and Source
Cols. A&B: As noted, these columms reflect AMI related data from DPL's 12+0 Update and AMI supplemental filings

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-27
Page 1 of 1

NOI-16, Gas Decoupling Customer Education

Line No.	Description	Amount (A)	Reference
1	Reverse Company Adjustment for Gas Decoupling Customer Education Expense	$ (106,500)	A

Notes and Source
A: Per Schedule WMV-10 (Adjustment No. 14) from DPL's 12+0 update filing

Delmarva Power & Light Company
Test Period Ended June 30, 2010

Docket No. 10-237
Schedule RCS-28
Page 1 of 1

NOI-17, Meals and Entertainment Expense

Line No.	Description	Amount (A)	Reference
1	Adjustment to Normalize Meals and Entertainment Expense	$ (12,900)	A

Notes and Source

A: Adjustment derived from data below per PSC-LA-248 (except as noted) and calculated as follows:

	Year	Total Company	
2	2007	$ 259,990	
3	2008	$ 318,360	
4	2009	$ 257,018	
5	Subtotal	$ 835,368	
6	Normalization Period	3	
7	Normalized Meals and Entertainment Expense	$ 278,456	
8	Test Period Meals and Entertainment	$ 462,741	per DPA-53
9	Adjustment to Meals and Entertainment	$ (184,285)	
10	Gas Allocation Factor	7%	
11	Adjustment to Meals and Entertainment for Gas	$ (12,900)	

DELMARVA POWER & LIGHT COMPANY
Docket No. 10-237
Appendix C
Copies of Delmarva's Responses to Data Requests and Documents Referenced in the Direct Tesimony and Schedules of Ralph C. Smith

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT PURSUANT
TO SECTION 13 OR 15(D) OF THE
SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported) September 4, 2007

WATERS CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**01-14010**	**13-3668640**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

34 Maple Street
Milford, Massachusetts 01757
(Address of principal executive offices) (Zip Code)

(508) 478-2000
(Registrant's telephone number, including area code)

N/A
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

On September 4, 2007, the Board of Directors of Waters Technologies Corporation approved a proposal to make certain changes to the Corporation's qualified and non-qualified retirement plans. The changes include freezing pay credit accruals under the Waters Retirement Plan (the "Retirement Plan") effective as of December 31, 2007 and increasing the employer matching contributions to the Waters Employee Investment Plan and the Waters Employee Investment Plan for Puerto Rico (the "401(k) Plans") beginning January 1, 2008. In connection with these changes, the Corporation will give Retirement Plan participants who are active as of December 31, 2007 a one-time transition benefit equal to the pay credit percentage such participants will receive in 2007 less 3% (which represents the additional employer matching contribution which will be available to participants in the 401(k) Plans in 2008), multiplied by three (3). This one-time transition benefit will be contributed to employees' 401(k) Plan accounts in the first quarter of 2008. The associated estimated expense will be recorded by the Corporation in Q3 2007.

The changes will also freeze pay credit accruals to essentially all participants in the Waters Retirement Restoration Plan (the "Supplemental Retirement Plan") and will update the Waters 401(k) Restoration Plan (the "Supplemental 401(k) Plan") to reflect the increased employer matching contributions and one-time transition benefit under the 401(k) Plans described above. These changes to the Supplemental Retirement Plan and the Supplemental 401(k) Plan are intended to be effective January 1, 2008.

The Board of Directors of Waters Technologies Corporation has delegated its authority to implement these changes to the proper officers of the Corporation who will consider amendments effecting the foregoing changes later in 2007.

At its meeting in December, the Board will consider additional amendments to the Supplemental Retirement Plan and the Supplemental 401(k) Plan as may be necessary to satisfy the requirements of Internal Revenue Code Section 409A. Note, however, that any changes required to comply with Code Section 409A are unrelated to the proposed plan freeze and reorganization described above.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Date: September 6, 2007

WATERS CORPORATION

By: /s/ John Ornell
Name: John Ornell
Title: Vice President, Finance and Administration and Chief Financial Officer

<< Previous Page | Next Page >>

Pension-Plan Freezes Likely To Ramp Up Next Year

Date :	03/20/2009 @ 9:30AM
Source :	Dow Jones News
Stock :	AON Corp. (AOC)
Quote :	↑ 39.3 0.16 (0.41%) @ 11:36AM

<< Back Quote Chart Financials Trades Level2

Pension-Plan Freezes Likely To Ramp Up Next Year

By Lynn Cowan

Of DOW JONES NEWSWIRES

The number of U.S. companies freezing their pension plans this year will represent the tip of the iceberg compared with the volume in years to come, according to pension experts.

Although a range of well-known corporations already have frozen their pensions - including Motorola Inc. (MOT), newspaper publisher McClatchy Co. (MNI) and insurer Aon Corp. (AOC) - there hasn't been a deluge of such decisions, which keep earned benefits intact but effectively bar employees from accruing more in the future. Actuaries and pension consultants say that many companies are so focused on resolving their overall business issues in the current economic climate that they can't focus on major, permanent shifts in employee benefits right now, but likely will re-evaluate their commitment to pensions beginning next year.

"When you look back at the last bear market from 2000 to 2002, the bulk of the uptick in plan closures and freezes happened after 2002. Companies had to deal with their immediate business issues first before addressing longer-term benefit planning," said Michael Archer, chief actuary at Towers Perrin. "Right now, most companies are saying, yes, pension issues are a problem, but we're not looking to close or freeze plans right away. It's in 2010 and 2011 where we could see higher activity, and get a better handle on the long-term effects of the downturn."

Right now changes to another type of retirement savings tool, 401 (k) plans, are far more common, most likely because any halt in company contributions is seen as a temporary measure that can be relatively easy to reverse in the future. There are also likely more freezes to come for traditional pension plans, experts agree, though the level is unlikely to top the pace seen in 2006, when many corporations decided to change their employee benefits as the Pension Protection Act (PPA), with a host of new regulations, was being signed into law.

"If you look back to 2006 and 2007, when a lot more plans were frozen, there were a few things that were the big drivers," said Scott Jarboe, a principal in benefits consultant Mercer's retirement, risk and finance business. "First, there were new (accounting) rules that drove more transparent reporting of pension details on the balance sheet. The second and more important issue was that the PPA was being finalized, and in most cases, corporations anticipated an increase in plan costs and volatility. A third, less fundamental issue, was that so many plan sponsors were freezing their pensions, that it created an opportunity to do the same and remain competitive," said Jarboe "The activity at that point was not driven by financially distressed companies," he said. "The issue we're going to see today is that plan sponsors who may have reviewed their plan designs and intend to remain committed to defined benefit pensions may be in such financial stress that they may have no choice but to freeze versus other more dramatic cost cutting measures."

There's disagreement among pension experts as to whether this economic climate will sound the death knell for traditional defined benefit plans in the years to come. In companies with unionized workforces, it will be harder to dislodge plans even if management has the desire. And while the market downturn has clearly exposed the risks involved with keeping a pension plan during tough times, there are advantages to having one under better conditions.

"Companies make two assumptions when they provide defined-benefit pensions: one, that contributions are tax-deductible; and secondly, companies count on the prospect that the market will subsidize the cost of the pension during good years," said Caitlin Long, head of the pensions solutions group at Morgan Stanley (MS).

Dan Yu, director of Eisner LLP's wealth management division, says he believes old-fashioned pensions were headed toward extinction even without the jolt they received from the market in 2008. "I would say, over the next decade, whether we are coming out of a recession or not, we'll see fewer. Defined benefit plans are dying dinosaurs. They won't exist in their present form after the next ten to 15 years," he said.

David Speier, a senior retirement consultant at Watson Wyatt Worldwide Inc. (WW), says he doesn't think the end is near, however. "I don't think that's a possibility. There are still private-sector companies out there that are committed to keeping defined benefit plans. There will be some that stick it out, even though we will clearly see more closures and plan freezes. But we won't be down to zero," he said.

-By Lynn Cowan, Dow Jones Newswires; 301-270-0323; lynn.cowan@dowjones.com

AON Corp. Historical Chart

AON Corp. Intraday Chart

Pension Publications

Companies That Have Changed Their Defined Benefit Pension Plans

Below is a list of employers that have announced significant changes to their defined benefit pension plans since December 2005. Changes include plan terminations, plan freezes for new and/or current employees, and changes to the formula by which pension benefits are calculated. For specifics, click on the employer's name to see the company's press release, SEC filing or news story announcing the change.

(Note: this is not a comprehensive list. These are only the changes that we are aware of, based on corporate press releases, news reports and other sources. This list does not include changes that have been made through the collective-bargaining process.)

Read our fact sheet on pension freezes. Visit our Reports page for studies on pension freezes and other topics. We have a similar list of companies that have reduced or eliminated their matching contributions to employees' 401(k) plans.

Announcement Date	Employer	Effective Date
03/23/2009	Advance Publications	05/15/2009
03/02/2009	Talbots, Inc.	05/01/2009
02/27/2009	B&C Trucking Company	unknown
02/25/2009	Regions Financial Corporation	04/16/2009
02/19/2009	E.W. Scripps Company	unknown
02/16/2009	Sparton Corporation	04/01/2009
02/13/2009	Atlanta Convention and Visitors Bureau	01/01/2009
02/05/2009	Aon Corporation	04/01/2009
02/05/2009	Cincinnati Bell	03/28/2009
02/05/2009	McClatchy Company	03/31/2009
01/15/2009	Saks, Inc.	01/30/2009
12/23/2008	Albany International Corporation	02/28/2009
12/23/2008	Seattle Times	02/06/2009

12/17/2008	Motorola	03/01/2009
12/17/2008	GenCorp Inc.	02/01/2009
11/21/2008	Random House, Inc.	12/31/2008
11/11/2008	Evening Post Publishing	01/10/2009
11/10/2008	R.H. Donnelly Corporation	01/01/2009
10/22/2008	New York Times Company	01/01/2009
09/24/2008	Xerium Technologies, Inc.	12/31/2008
09/15/2008	Equifax	01/01/2009
07/08/2008	YRC Worldwide Inc.	07/01/2008
06/24/2008	Boeing	01/01/2009
06/11/2008	Gannett	08/01/2008
04/25/2008	Standard Register	unknown
04/16/2008	Beneficial Mutual Bancorp Inc.	06/30/2008
03/31/2008	3M	01/01/2009
02/12/2008	Bryn Mawr Bank Corporation	03/31/2008
02/2008	Northrop Grumman	07/01/2008
12/05/2007	Neiman Marcus, Inc.	12/31/2007
11/16/2007	Milacron Inc. (see p. 22)	12/31/2007
11/06/2007	Foamex International Inc.	01/01/2008
10/02/2007	Haynes International, Inc.	01/01/2008
09/24/2007	State Street Corp.	01/01/2008
09/11/2007	Andersen Corp.	01/01/2008
09/07/2007	Delphi Corporation	TBD
09/04/2007	Waters Corporation	12/31/2007
08/09/2007	Center Bancorp, Inc.	09/30/2007
07/17/2007	Dow Chemical Company	01/01/2008
05/01/2007	ArvinMeritor, Inc.	01/01/2008
04/24/2007	NASDAQ	05/01/2007
04/12/2007	Dun & Bradstreet Corp.	06/30/2007
03/29/2007	Fidelity Investments	06/01/2007
03/20/2007	Dana Corporation	07/01/2007

02/28/2007	Tecumseh Products Co.	05/01/2007
02/28/2007	Goodyear Tire & Rubber Company	01/01/2008
02/27/2007	FedEx	06/01/2008
02/23/2007	SureWest Communications	04/10/2007
02/20/2007	HP (Hewlett-Packard)	01/01/2008
02/16/2007	SunTrust Banks Inc.	01/01/2008
01/11/2007	Ryder System, Inc.	01/01/2008
11/30/2006	Shenandoah Telecommunications	01/31/2007
11/29/2006	Kershaw County Medical Center	01/01/2007
11/15/2006	North Pittsburgh Telephone Co.	12/31/2006
11/08/2006	Whirlpool Corporation	01/01/2007
11/08/2006	Vought Aircraft Industries, Inc.	12/31/2007
11/03/2006	Citigroup	01/01/2008
11/02/2006	Belo Corp.	03/31/2007
11/01/2006	Aon Corporation	01/01/2007
11/01/2006	Met-Pro Corporation	12/31/2006
11/31/2006	Lenox Group Inc.	01/01/2007
10/30/2006	MeadWestvaco Corporation	01/01/2007
10/30/2006	Michelin	01/01/2017
10/26/2006	Tredegar Corporation	12/31/2007
10/19/2006	Journal Register Company	01/01/2007
10/18/2006	LSB Corporation	12/31/2006
10/17/2006	Con-Way Inc.	12/31/2006
10/11/2006	Remington Arms Company, Inc.	01/01/2008
10/10/2006	The Hershey Company	01/01/2007
09/27/2006	NCR Corporation	01/01/2007
09/20/2006	Calgon Carbon Corporation	12/31/2006
09/07/2006	Alliant Techsystems	01/01/2007
08/31/2006	Flushing Financial Corporation	09/30/2006
08/28/2006	DuPont	01/01/2008
08/23/2006	Tenneco Inc.	01/01/2007

08/08/2006	Blount International, Inc.	01/01/2007
08/01/2006	Harry & David Operations Corp.	07/01/2007
07/21/2006	Reynolds and Reynolds Company	10/01/2006
06/29/2006	The Stride Rite Corporation	12/31/2006
06/27/2006	Nortel	01/01/2008
06/23/2006	G&K Services, Inc.	01/01/2007
06/15/2006	Bandag, Incorporated	12/31/2006
05/15/2006	Media General, Inc.	12/31/2006
05/01/2006	Lydall, Inc.	06/30/2006
04/27/2006	A.T. Cross Company	05/20/2006
03/22/2006	Unisys Corporation	12/31/2006
03/20/2006	Lincoln Electric Holdings, Inc.	01/01/2006
03/07/2006	General Motors Corp.	01/01/2007
02/23/2006	Wellpoint, Inc.	01/01/2006
02/22/2006	Coca-Cola Bottling Co. Consolidated	06/30/2006
02/20/2006	Stepan Company	07/01/2006
02/15/2006	Ferro Corporation	04/01/2006
01/26/2006	Harleysville Group Inc.	04/01/2006
01/24/2006	Lexmark International, Inc.	05/01/2006
01/19/2006	Russell Corporation	04/01/2006
01/16/2006	Alcoa	03/01/2006
01/13/2006	Armstrong World Industries, Inc.	03/01/2006
01/05/2006	IBM	01/01/2008
12/05/2005	Verizon Communications Inc.	07/01/2006

United States Government Accountability Office

GAO

Report to Congressional Addressees

July 2008

DEFINED BENEFIT PENSIONS

Plan Freezes Affect Millions of Participants and May Pose Retirement Income Challenges

GAO

Accountability * Integrity * Reliability

GAO-08-817

July 2008

GAO
Accountability·Integrity·Reliability

Highlights

Highlights of GAO-08-817, a report to congressional addressees

DEFINED BENEFIT PENSIONS

Plan Freezes Affect Millions of Participants and May Pose Retirement Income Challenges

Why GAO Did This Study

Private defined benefit (DB) pension plans are an important source of retirement income for millions of Americans. However, from 1990 to 2006, plan sponsors have voluntarily terminated over 61,000 sufficiently funded single-employer DB plans. An event preceding at least some of these terminations was a so-called plan "freeze"—an amendment to the plan to limit some or all future pension accruals for some or all plan participants. Available information that the government collects about frozen plans is limited in scope and may not be recent. GAO conducted a stratified probability sample survey of 471 single-employer DB plan sponsors out of a population of 7,804 (with 100 or more total plan participants) to gather more timely and detailed information about frozen plans. We have prepared this report under the Comptroller General's authority as part of our ongoing reassessment of risks associated with the Pension Benefit Guaranty Corporation's (PBGC) single-employer pension insurance program, which, in 2003, we placed on our high-risk list of programs that need broad-based transformations and warrant the attention of Congress and the executive branch. Frozen DB plans have possible implications for PBGC's long-term financial position. This report examines (1) the extent to which DB pension plans are frozen and the characteristics of frozen plans; and (2) the implications of these freezes for plan participants, plan sponsors, and the PBGC.

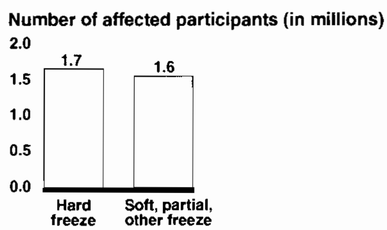
To view the full product, including the scope and methodology, click on GAO-08-817. To view the survey results click on GAO 08-818SP. For more information, contact Barbara Bovbjerg, at (202) 512-7215 or bovbjergb@gao.gov.

What GAO Found

Frozen plans are fairly common today, with about half of all sponsors in our study population having one or more frozen DB plans. Overall, about 3.3 million active participants in our study population, who represent about 21 percent of all active participants in the single-employer DB system, are affected by a freeze. The most common type of freeze is a hard freeze—a freeze in which all future benefit accruals cease—which accounts for 23 percent of plans in our study population; however, an additional 22 percent of plans are frozen in some other way. Larger sponsors (i.e. those with 10,000 or more total participants) are significantly less likely than smaller sponsors to have implemented a hard freeze, with only 9 percent of plans under a hard freeze among larger sponsors compared with 25 percent of plans under a hard freeze among smaller sponsors. The vast majority of sponsors with frozen plans in our study population, 83 percent, have alternative retirement savings arrangements for these affected participants, but 11 percent of sponsors do not. (An additional 6 percent of sponsors froze plans under circumstances that preclude a replacement plan.) Plan sponsors cited many reasons for freezing their largest plans but most often noted two: the impact of annual contributions on their firm's cash flows and the unpredictability of plan funding. Sponsors of frozen plans generally expressed a degree of uncertainty about the anticipated outcome for their largest plan, but sponsors whose largest plan was hard frozen were significantly more likely to anticipate plan termination as the likely plan outcome.

The implications of a freeze vary for sponsors, participants, and PBGC. For plan sponsors, while hard freezes appear to indicate an increased likelihood of plan termination, a rise in plan terminations has yet to materialize. For participants, a freeze generally implies a reduction in anticipated future retirement benefits, though this may be somewhat or entirely offset by increases in other benefits or a replacement retirement-savings plan. However, because the replacement plans offered to affected participants most frequently are defined contribution, the investment risk and responsibility for saving are shifted to employees. Finally, plan freezes may potentially improve PBGC's net financial position, but the degree to which it is accompanied by sponsor efforts to improve plan funding is unclear. In any event, the shrinking of the single-employer pension insurance program plan base seems likely to continue.

Estimated Number of Active Participants Affected by Sponsors' Largest Plan Freeze, by Freeze Type



Source GAO analysis of survey of DB pension plan sponsors regarding frozen plans

Frozen Plans Affect about One-Fifth of Active DB Plan Participants

Overall, an estimated 3.3 million active participants[6] in our study population—or 21 percent of all active participants in the private, single-employer DB system—are affected by reported freezes. (See app. I, slide 9 and slide 10.) Active participants are employees that are or may become eligible to accrue or receive additional benefits under a plan; if all participants in the DB system (that is, active participants, retirees, and separated vested participants) are considered, the proportion represented by active participants who are affected by plan freezes falls to 10 percent.[7] (See app. I, Slide 9.) We considered only those participants who are currently accruing benefits (that is, active participants) at the time of freeze implementation to be affected by a freeze. The above calculations, therefore, do not include sponsors whose largest frozen plans are under a new-employee-only soft freeze, where the plan is closed to new entrants and benefit accruals for active participants remain unchanged. The extent to which active participants are affected by a freeze depends on the type of freeze in place. Under hard freezes, future benefit accruals cease for active participants. In contrast, soft freezes may reduce future benefit accruals for some or all active participants. Soft freezes are distinct from hard freezes in that the restrictions on participants' future benefit accruals are less comprehensive than the total cessation of future accruals under hard freezes.[8]

Our survey shows that about half the sponsors in the study population have one or more frozen plans. (See app. I, slide 11.) Overall, about

[6]All estimates based on our sample are subject to sampling error. For example the 95 percent confidence interval of the total participant estimate ranges from 2.25 million to 4.34 million participants. Unless otherwise noted, all percentage estimates based on this survey have 95 percent confidence intervals of within +/- 11 percentage points of the estimate itself. Of the 3.3 million estimated participants affected by a freeze, 1.7 million are affected by a hard freeze, and 1.8 million are affected by a soft, partial, or other freeze. The 95 percent confidence interval for participants affected by hard freeze is from 1.1 million to 2.3 million. The 95 percent confidence interval for participants affected by soft, partial, or other freezes is from 0.7 million to 2.5 million. See appendix II for additional information on sampling error of estimates.

[7]Active participants may continue to accrue benefits because they are currently employed by the sponsoring firm. Retirees are no longer employed by the firm and are collecting their retirement benefits. Separated vested participants are no longer employed by the sponsoring firm and no longer accrue benefits, but they are not yet collecting their retirement benefits.

[8]See appendix I, slide 5 for general freeze type definitions. Exact definitions used in the survey may be found in the special product supplement. See GAO, *Defined Benefit Pensions: Survey of Sponsors of Large Defined Benefit Pension Plans*, GAO-08-818SP (Washington, D.C.: July 21, 2008).

51 percent of plans in the study population were reported as closed to new entrants, the basic requirement of a plan freeze. Nearly half of plans with a reported freeze, or 23 percent of all plans in the study population, were under a hard freeze. (See app. I, slide 12.)[9] In addition, 12 percent reported some type of soft freeze. About 6 percent reported a partial plan freeze, while 4 percent reported an "other" freeze, which include situations where plan participants are separated into plan tiers,[10] or freezes brought on by bankruptcy, plant closure, or plan merger.

The survey results suggest that two factors may influence the likelihood that sponsors will implement a hard freeze: sponsor size and the extent to which a sponsor's plans are subject to collective bargaining (CB) agreements. Larger sponsors, those with 10,000 or more total participants, are significantly less likely than smaller sponsors to have implemented a hard freeze, with only 9.4 percent of plans under a hard freeze among larger sponsors compared with 25.4 percent of plans under a hard freeze among smaller sponsors. (See app. I, slide 13.) Similarly, firms with some or all plans subject to CB are significantly less likely to implement hard freezes than sponsors with no plans subject to CB.[11] (See app. I, Slide 14.) However, these two factors may be related, as larger sponsors in our

[9]Closed and unclassified plans are only included for this analysis (see app. I, slide 12). In other analyses, only those plans reporting a specific freeze type will be included in calculations of frozen plans. Of the 51 percent of all plans reported as closed to new entrants, 44 percent reported a specific freeze type. Another roughly 9 percent of plans were closed to new entrants but were not classified by their sponsors as being frozen. Those plans defining a freeze plus those that reported the plan as closed to new hires, but not defined as frozen, may not sum to the total number of closed plans. This occurs because, in certain instances, a partial freeze may not be closed to all new entrants. For example, a subset of new entrants may be part of the group unaffected by the partial freeze.

[10]An example of a tier might be if an employer were to offer certain participants the option to freeze certain accruals in one DB plan as a condition of participation and accruals in another, alternative plan (either DB or DC).

[11]The statistical significance of this finding applies only to hard frozen plans. Sponsors with some or all plans that were subject to CB did not freeze their plans overall at a statistically different rate from the general population of sponsors. Estimated percentages for sponsors with no CB or some CB have 95 percent confidence intervals of within +/- 11 percentage points of the estimates themselves. For sponsors with all plans subject to CB, the confidence intervals are within +/- 15 percentage points of the estimates themselves.

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Background: What Is a Plan Freeze?

- A plan freeze is a plan amendment that closes the plan to new entrants and may limit future benefit accruals for some or all active plan participants
- General types include:
  - -Hard Freeze – the plan is closed to new entrants and participants no longer accrue additional benefits
  - -Soft Freeze – at a minimum the plan is closed to new entrants. The plan's prospective benefit formula may or may not be changed in such a way as to limit future benefit accruals for participants.
  - -Partial Freeze – the plan is closed to new entrants and, for only a subset of active participants, the plan's prospective benefit formula is changed to limit or cease future benefit accruals.

5

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Background: Freeze Data

- Most reports of pre-2003 freezes were based on:
  - limited data obtained from restricted/proprietary client bases of consulting firms and
  - survey questions on freezes that were often indirect or could be misconstrued
- The Pension Benefit Guaranty Corporation (PBGC) began analyzing generalizable information on single-employer, "hard frozen" plans in 2005 (using plan year 2003 data)
- Most recent PBGC data shows that:
  - 14 percent of plans were hard frozen as of 2005
  - There has been a nearly 50 percent increase in frozen plans since 2003
  - Hard freezes are generally more prevalent among smaller plans

6

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Defined Benefit Pensions: Survey of Sponsors of Large Defined Benefit Pension Plans (GAO-08-818SP, July 2008), an E-supplement to GAO-08-817

Read the Full Report: Defined Benefit Pensions: Information from GAO Survey on Frozen Defined Benefit Plans (GAO-08-817)
Background Information

Instructions for Viewing This Survey

Table of Contents

Background

Over the last five years, a number of large, high profile employers have announced their intention to freeze-- an amendment to the plan to limit some or all future pension accruals for some or all plan participants-- their larger defined benefit (DB) plans that represent a significant portion of plan liabilities and plan participants in the private DB system. To better understand the current plan freeze environment and its significance to the DB system going forward, GAO conducted a study of sponsors of tax-qualified, single-employer, defined benefit (DB) plans that had 100 or more total participants. Specifically, we surveyed a stratified probability sample of plan sponsors about their experiences with DB plans and plan freezes. We obtained a weighted response rate of 78 percent. A more detailed discussion of our scope and methodology is contained in our report: Defined Benefit Pensions: Plan Freezes Affect Millions of Participants and May Pose Retirement Income Challenges, GAO-08-817 (Washington, D.C.: July 21, 2008). We administered the survey from November, 2007 through May 2008 in accordance with generally accepted government auditing standards.

Instructions for Viewing this Survey

Special Viewing Instructions

These tables are a product of combining the results of two questionnaires-- the first 17 questions and last question from a web questionnaire to large plan sponsors (with 50,000 or more participants) and a shorter mail questionnaire with the same 18 questions to smaller plan sponsors (100 to less than 50,000 participants). This document presents the results using the web survey format, including the navigation and introduction material from the web survey.

How to View The Surveys

Click on the Table of Contents link located in the lower right of this screen. To read to the bottom of the screen, you may need to use your scroll bar on the right side of this screen.

The first screen in the survey is an introduction and general information that was sent to and viewed by recipients of the survey. There are no survey results to view on this screen. This screen is for information only and you may by-pass it by clicking on Next located at the bottom of the screen in the lower right.

The survey may have links to allow respondents to bypass inapplicable questions (skip patterns). While these were active links during the data collection period, they have now been disabled.

When a respondent wrote a narrative response to a question, we sometimes present the percent of respondents making a comment.

How to View the Responses for Each Question

To view the responses to each question, click on the question number (Links to survey questions will look like this: 1., etc.).

After viewing the responses to each question, click on the "x" in the upper right corner of your screen to close that window and return to the questionnaire.

How to Return to a Page That You Previously Visited

To return to the last screen you viewed, click the Previous button on the lower right corner of the screen.

Click the Next button to advance to the next screen.

How to Make the Font Larger on Your Screen

You can make the font larger by changing your browser setting. For example, on Internet Explorer you can change the font size by going to View and selecting Text Size.

Contact Information?

If you have questions concerning these data, please contact Barbara Bovbjerg at (202) 512-5491 or by e-mail at Barbara Bovbjerg.

(130851)

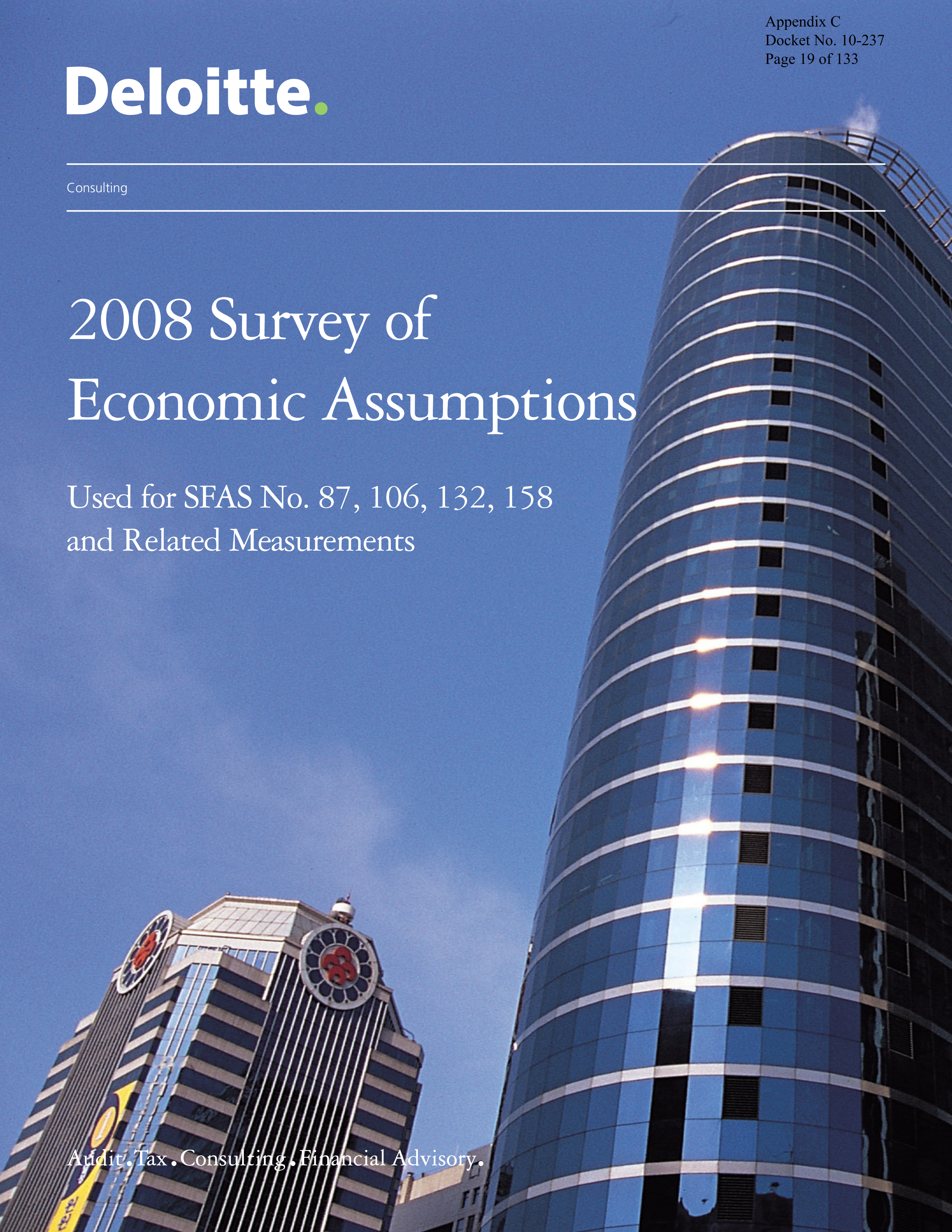
Table of Contents

Deloitte.

Consulting

2008 Survey of Economic Assumptions

Used for SFAS No. 87, 106, 132, 158 and Related Measurements



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Introduction

Contents

Statement of Financial Accounting Standards No. 87 (Statement 87) requires the sponsor of a defined benefit pension plan measure the plan's obligations and annual expense using assumptions that (1) individually reflect best estimates (paragraph 43) and (2) are "consistent [with each other] to the extent that each reflects expectations of the same future economic conditions" (paragraph 46). In general, the benefit obligation is most sensitive to the discount rate assumption; for example, a relatively small change in the discount rate (of say, 25 basis points) could result in a change in the liabilities of perhaps as much as 5 percent.

The Financial Accounting Standards Board (FASB) describes the methodology to select the discount rate (Statement 87 paragraph 44). The discount rate should reflect the rates at which the pension benefits could be effectively settled. Further guidance (paragraph 44A1) provides that the discount rate should reflect the yield of a portfolio of high-quality fixed-income instruments whose coupons and maturities match projected benefit payments However, the literature allows the use of computational shortcuts (cf. paragraph 10 of Statement 87 and paragraph 15 of Statement 106), whose results can be expected to produce results that are not materially different than a more detailed analysis. Because the duration of a plan's benefit obligation is affected by the plan design and by the demographic characteristics of the plan population (e.g., average age, average service, proportion of retirees), one might generally expect that plans with similar plan designs and demographics would use similar discount rates. Conversely, one might expect that plans with dissimilar plan designs or demographics may not use similar discount rates.

Of course, there may be circumstances -- such as a relatively flat yield curve -- in which plans with dissimilar plan designs or demographics would be able to support similar discount rates. In summary, the process to select the discount rate considers the facts and circumstances specific to the plan as well as the prevailing high-quality corporate bond yield rates as of the measurement date.

Statement of Financial Accounting Standards No. 106 (Statement 106) contains similar requirements for the selection of assumptions for Other Postretirement Employee Benefit plans (paragraphs 29 and 42). Similar guidance is also provided for the selection of discount rate (paragraph 31 and 31 A[1]).

Companies also disclose other economic assumptions: the expected rate of return on plan assets, the expected rate of salary increases, and the expected increase in health care costs.

Although the selection of assumptions should be specific to the individual plan, plan sponsors, as well as regulators, often compare their discount rate and other assumptions to those of other plan sponsors.

In this survey, Deloitte's Human Capital service area has compiled information disclosed by many of the Fortune 500 companies in their most recent annual reports. We have focused on 233 companies that sponsor pension and/or other postretirement benefits and who have calendar fiscal years. Of these, 232 companies who have disclosed defined benefit plans; 206 companies disclosed Other Postretirement Employee Benefit plans (OPEB, subject to Statement 106), including one company that disclosed only OPEB benefits. This disclosure information also included assumptions used as of the prior year, enabling us to compare changes in the assumptions from one year to the next.

[1] Statement of Financial Accounting Standards No. 158 (Statement 158) amended Statement 87 and 106. These amendments include the addition of paragraph 44A to Statement 87 and 31A to Statement 106; this guidance previously was located in the Basis for Conclusions of Statement 106. Statement 158 also provided that the unfunded benefit obligation be recognized on the balance sheet for fiscal years ending after December 15, 2006 (delayed to June 15, 2007 for non-publicly held entities) and that the measurement date be aligned with fiscal year end for fiscal years ending after December 15, 2008.

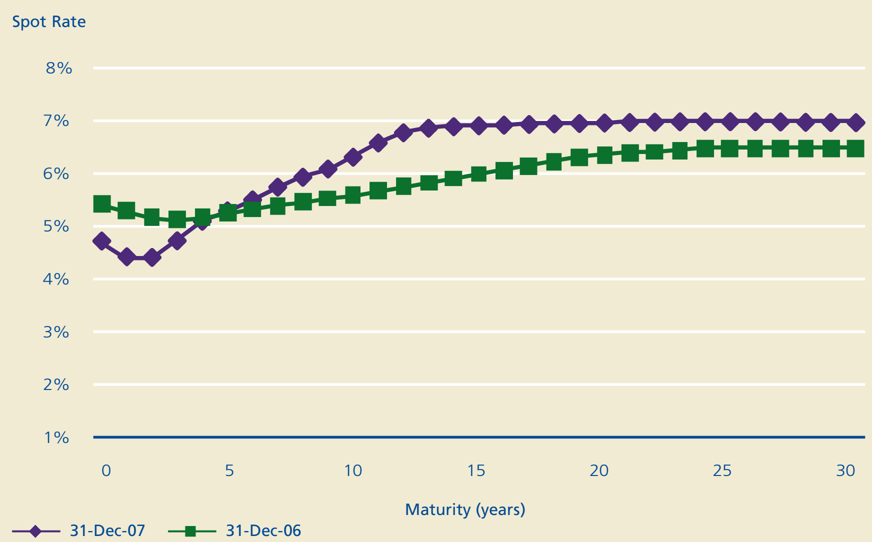
Prevailing Interest Rates

With respect to the guidance regarding the selection of the discount rate, the SEC staff has indicated that it believes the term "high-quality" refers to those fixed-income instruments with at least an Aa3 rating from Moody's (or its equivalent from another rating service)[2]. Exhibit 1a shows the yield curve on the Bloomberg Composite Aa3 bonds at both December 31, 2007, and December 31, 2006. Exhibit 1b shows the Citigroup Pension Discount Curve at the same dates.

Taken together, these Exhibits indicate that the yield curve has inverted more in the early years as compared to last year. Yields after around the 5 year maturity point have increased across the rest of the curve.

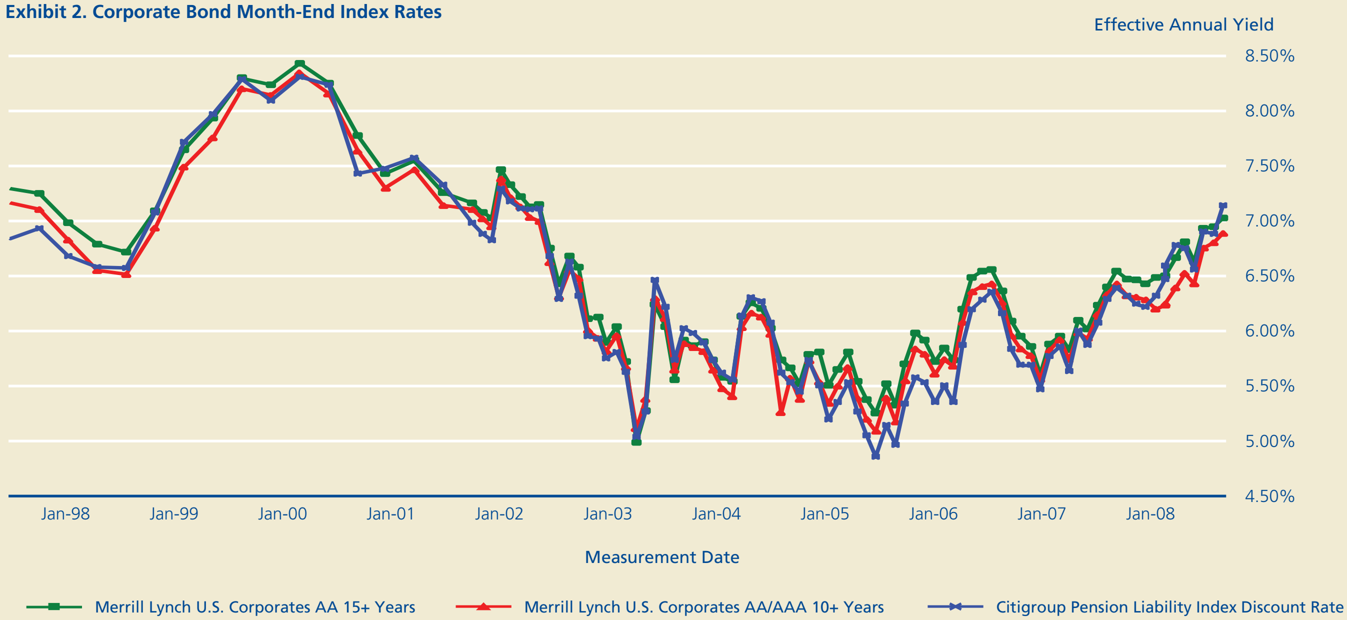
Exhibit 1a. Bloomberg Composite Aa3 Spot Yields

Exhibit 1b. Citigroup Pension Dicount Curve



[2] Cf. EITF Topic D-36.

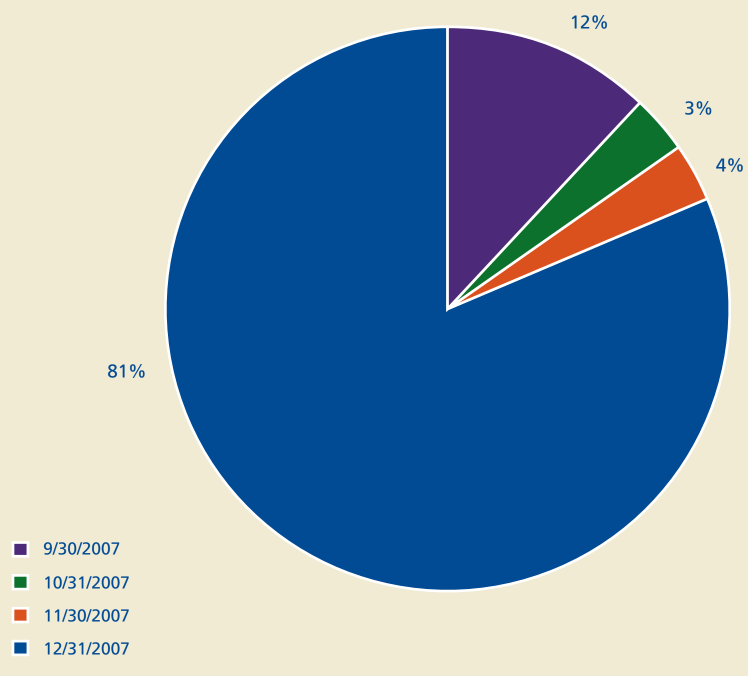
Exhibit 2. Corporate Bond Month-End Index Rates



Over the past several years, the rates available on corporate bonds (as suggested by published indices such as Merrill Lynch U.S. Corporates Aa 15+ years, Merrill Lynch U.S. Corporates Aa/Aaa 10+ years, as well as Citigroup's (formerly Salomon's) Pension Liability Index) have varied considerably. The historic yields over the past several years for all of these indices are plotted in Exhibit 2.

This exhibit indicates that these indices finished the year with yields about 50 basis points more than the end of 2006. Furthermore, Exhibit 2 indicates that rates are currently (as of the end of June 2008) up about 35 to 50 basis points since the end of 2007.

Exhibit 3. Measurement Dates



Measurement Date

As shown in Exhibit 3, approximately 19 percent of the companies surveyed used a measurement date prior to December 31, with September 30 being the most common of those. Currently, the measurement date can precede the disclosure date by up to three months (see paragraph 52 of Statement 87; paragraph 72 of Statement 106), although, for fiscal years ending after December 15, 2008, the fiscal year end will have to be used. For purposes of the remainder of this survey, we have only included companies with a December 31 measurement and disclosure date.

Discount Rate

Exhibit 4 summarizes the discount rate for Statement 87 purposes disclosed as of December 31, 2007, and December 31, 2006. The average discount rate disclosed at December 31, 2007, was 6.20 percent, about 41 basis points above that disclosed at the end of 2006. Eighty-eight percent of the companies surveyed were between 6.00 percent and 6.50 percent.

Most of the companies surveyed disclosed a discount rate within a narrow range at both December 2007 and December 2006; in each year, 13 percent or fewer disclosed at a discount rate that was more than 25 basis points from the average.

The FASB and SEC staffs have indicated that they expect discount rates to move with general economic trends[3]. Exhibit 5 presents the change from December 31, 2006, to December 31, 2007. The SEC staff has further indicated that they expect any company that relies on an index to support its selection of the discount rate to provide evidence that such index is appropriate for the particular plan.

If the registrant benchmarks its assumption off of published long- term bond indices, it is expected to explain how it determined that the timing and amount of cash outflows related to the bonds included in the indices matches its estimated defined benefit payments. If there are differences between the terms of the bonds and the terms of the defined benefit obligations (for example if the bonds are callable), the registrant is expected to explain how it adjusts for the difference. Increases to the benchmark rates should not be made unless the registrant has detailed analysis that supports the specific amount of the increase.[4]

Exhibit 4. Discount Rates for Disclosures

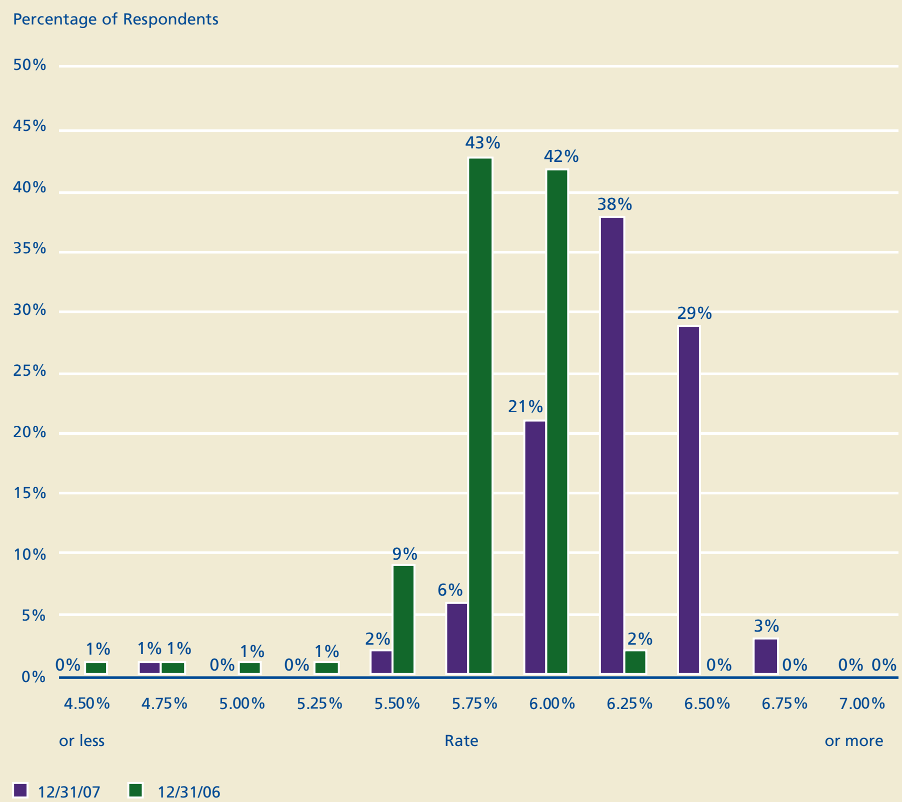
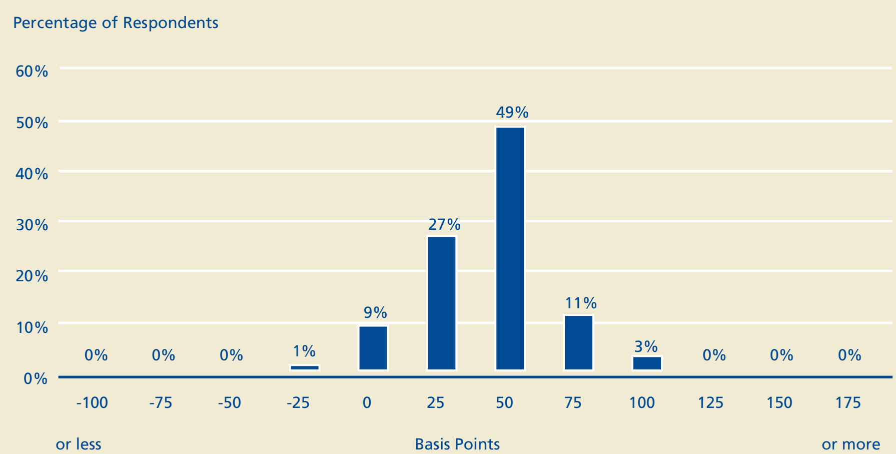


Exhibit 5. Change in Discount Rate

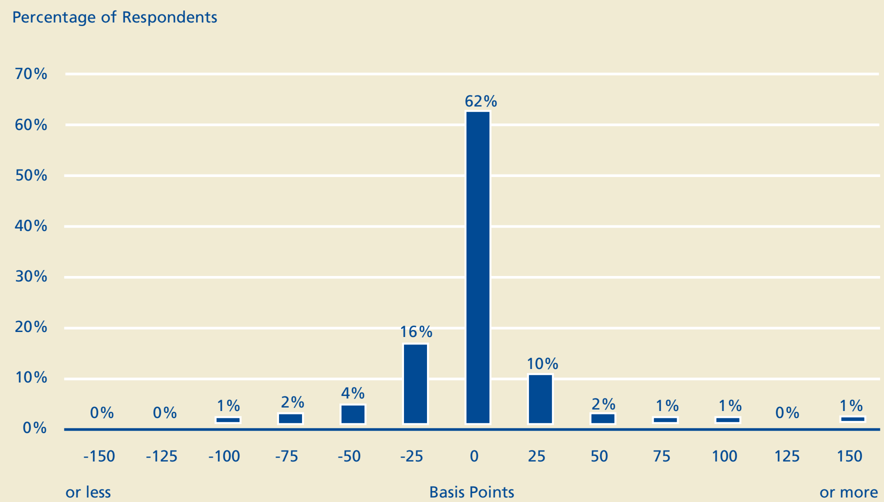


[3] Cf. EITF Topic D-36.
[4] Cf. Section II H 1 at www.sec.gov/divisions/corpfin/acctdis030405.htm

On average, discount rates increased by about 41 basis points from December 31, 2006, to December 31, 2007. While approximately 9 percent of the companies in our survey did not change the discount rate, 49 percent of the companies increased it by 50 basis points.

We also compared the discount rate disclosed for Statement 106 purposes with that disclosed for measuring pension liabilities in accordance with Statement 87. As shown in Exhibit 6, 62 percent of the companies surveyed disclosed the same discount rate for both measurements. Fifteen percent of companies disclosed a higher discount rate for measuring postretirement benefits than for measuring pension benefits.

Exhibit 6. Difference in Discount Rate for SFAS 106 Purposes and SFAS 87 Purposes

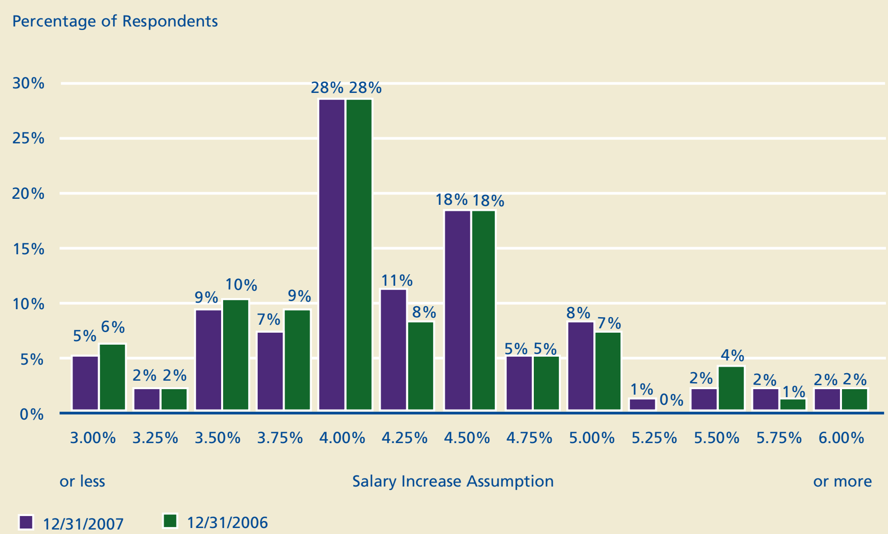


Salary Increase Assumption

Plans that provide pay-related benefits are required to disclose the salary increase assumption underlying the calculations. Almost all of the companies in the survey disclosed a salary increase assumption. Statement 87 provides relatively little guidance in the selection of the salary increase assumption other than to mention that it should reflect "future changes attributed to general price levels, productivity, seniority, promotion, and other factors" (paragraph 46).

There is a fairly wide range of assumed salary increase as summarized in Exhibit 7. The average salary increase assumption disclosed as of December 31, 2007, was roughly 4.23 percent, a decrease of 6 basis points from 2006. Seventy percent of the companies surveyed used an assumption between 4.0 and 5.0 percent. Twelve percent were 100 or more basis points away from the average. The rates disclosed at December 31, 2006, show a similar pattern of dispersion around the average.

Exhibit 7. Salary Increase Disclosures



This range of expected salary increase assumption is also seen in the spread between the discount rate and the salary increase assumptions. Exhibit 8 shows this difference as of December 31, 2007, and December 31, 2006. While the average spread increased by roughly 37 basis points, the companies surveyed are dispersed over the range.

Exhibit 9 shows the change in the salary increase assumption from December 31, 2006, to December 31, 2007.

Between these two measurement dates, 79 percent of the companies surveyed reported no change in the salary increase assumption, similar to last year. Roughly 11 percent increased this assumption by 25 or 50 basis points.

Exhibit 8. Spread Between Discount Rate and Salary Increase Assumption

Percentage of Respondents

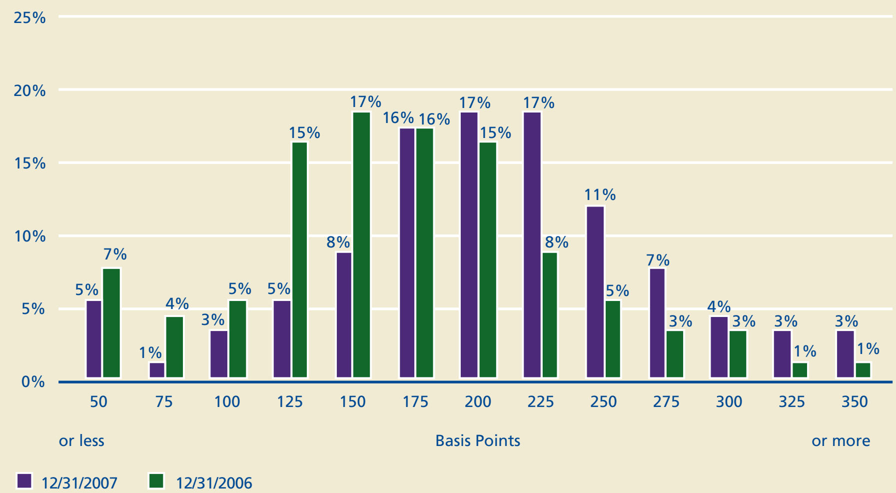
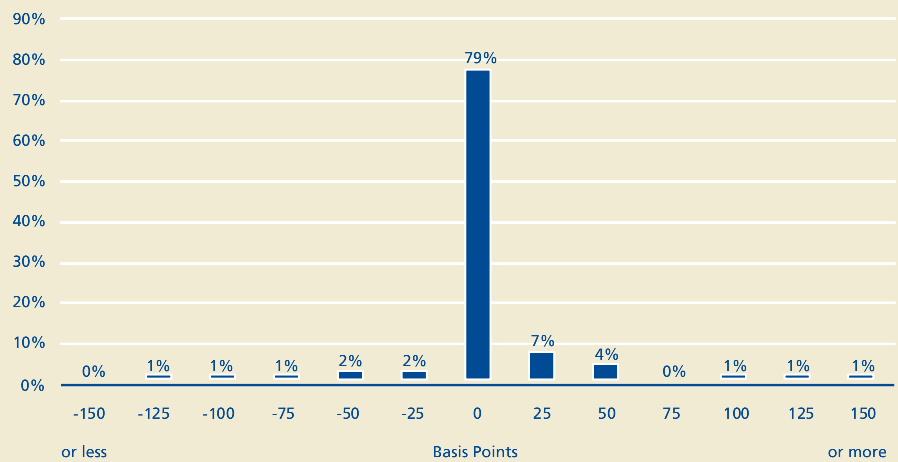


Exhibit 9. Change in Salary Increase Assumption

Percentage of Respondents



Expected Return Assumption

Paragraph 45 of Statement 87 specifies that the Expected Long-Term Rate of Return assumption (Expected Return) should "reflect the average rate of earnings expected on the funds invested or to be invested to provide for the benefits...." Furthermore, Statement No. 132R requires that plan sponsors provide a narrative description of both a plan's actual investment policy and the basis used to determine the overall expected long-term rate of return. As a result, companies with different asset allocations or different investment philosophies may have different long-term return assumptions.

In this context, we understand that some companies engage in a process (with varying degrees of rigor) for developing the Expected Return assumption.

One method for determining the Expected Return assumption is based on a building block approach. In our experience, the building block approach is used by many in the investment management industry to develop capital market expectations. This approach begins with the development of a long-term level of expected inflation. The level of inflation becomes the "building block" for the development of expected returns for each of the various asset classes (being the difference between real and nominal returns).

Next, an expected return on cash ("risk free" asset) is developed, typically using 90 day Treasury bills as a proxy. Risk premiums above cash are developed as the primary determinant of expected return for the various asset classes (e.g., US equities, US core fixed income, etc.) included in the portfolio. Risk premiums should reflect the risk of each asset class (the riskier the asset class, the larger the risk premium).

Finally, under the building block approach, the expected return of the total portfolio is calculated using the asset class returns developed and taking into account the overall strategic asset allocation of the portfolio. Some companies engaging in active investment management may choose to incorporate a return premium to reflect their belief that active management will provide an additional incremental return. It is important to note that management fees for actively managed investments are typically higher than passively managed products, and that the premium assigned for active management should be net of additional investment management fees.

Another approach to developing the long-term rate of return assumption is to develop a consensus forecast, whereby the company gathers long-term capital market forecasts from multiple, reputable organizations in the financial services industry (such as investment consultants, investment managers, or other financial institutions). Typically these capital market forecasts include long-term expected return assumptions for various asset classes. The company can calculate the expected return of the portfolio by "averaging" the expected return forecasts gathered by asset class, and using these inputs to calculate the total expected return on the overall portfolio.

Alternatively, some companies may choose to determine the projected range of returns for the overall portfolio by using stochastic simulation. Stochastic simulation is a tool that allows the company to forecast the overall portfolio return under various potential economic environments. The inputs to the model typically include mean-variance assumptions for each asset class (which can be generated by using the building block methodology or consensus forecast), as well as assumptions relating to future levels of inflation and interest rates. The results of the stochastic simulation will provide the company with the range of potential returns for the portfolio over a long-term horizon (although it is worth noting that the output of the analysis is largely predicated upon the assumptions).

Exhibit 10 shows the range of the Expected Return used in calculating pension expense for 2007 and 2006. While Statement 106 has a similar requirement (paragraph 32), most OPEB plans are unfunded; this assumption is not used in the case of an unfunded plan.

The average Expected Return was 8.13 percent for 2007 (roughly 3 basis points lower than was used for 2006), with 79 percent of the companies surveyed using between 8.00 and 9.00 percent. Twenty one percent reported an Expected Return of less than 8 percent; no companies reported an Expected Return of 9.25 percent or more. As compared to 2006, approximately 9 percent of companies surveyed lowered this assumption in 2007. As shown in Exhibit 11, seven percent of the companies reduced this assumption 25 basis points and another 2 percent reduced it 50 basis points. Three percent of the companies surveyed increased this assumption.

Exhibit 10. Expected Long-Term Rate of Return Assumption

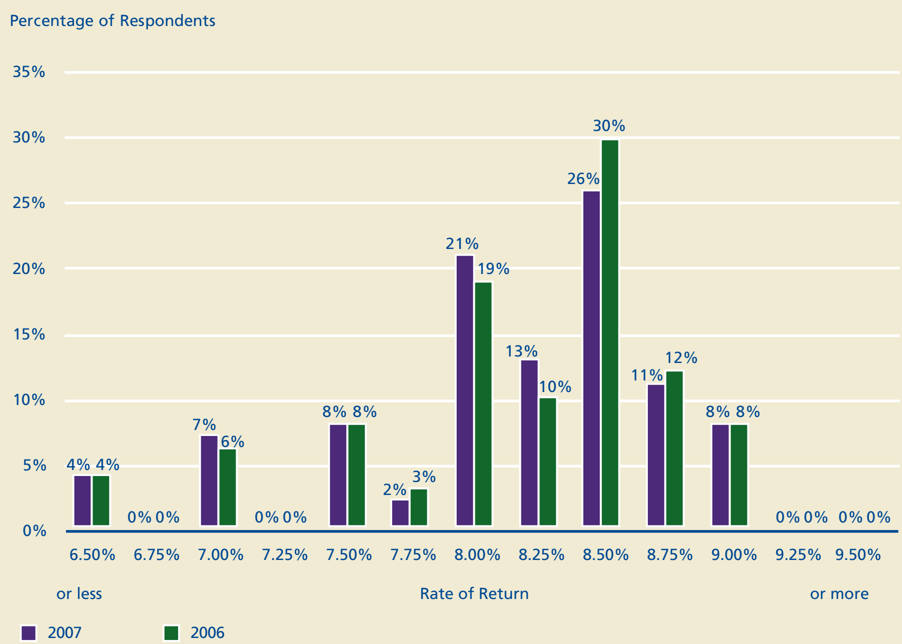
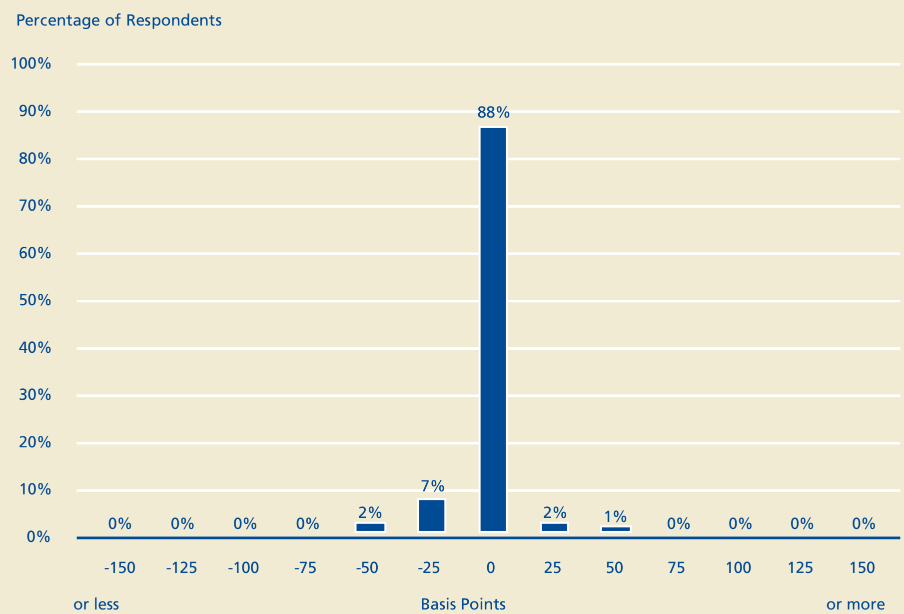


Exhibit 11. Change in Expected Long-Term Rate of Return Assumption



Health Care Cost Trend

Paragraph 39 of Statement 106 describes the Health Care Cost Trend assumption as representing "the annual change in the cost of health care benefits... for each year from the measurement date until the end of the period in which benefits are expected to be paid." This paragraph also makes the observation that "health care cost trend rates may be assumed to continue at the present level for the near term, or increase for a period of time, and then grade down over time to an estimated health care cost trend rate ultimately expected to prevail."

As of December 31, 2007, 73 percent of the companies surveyed disclosed an initial Health Care Cost Trend assumption of between 8.00 percent and 9.00 percent. Sixteen percent used a higher initial trend and the remaining plans disclosed a lower trend assumption. A comparison of the current and prior year is shown in Exhibit 12.

The average initial trend rate was 8.75 percent, down 34 basis points from the 9.09 percent disclosed for the prior year. Just 33 percent of companies surveyed used the same rate (as shown in Exhibit 13). Thirty-six percent changed their initial rate by 100 basis points or more (in either direction).

Exhibit 12. Initial Health Trend Rates

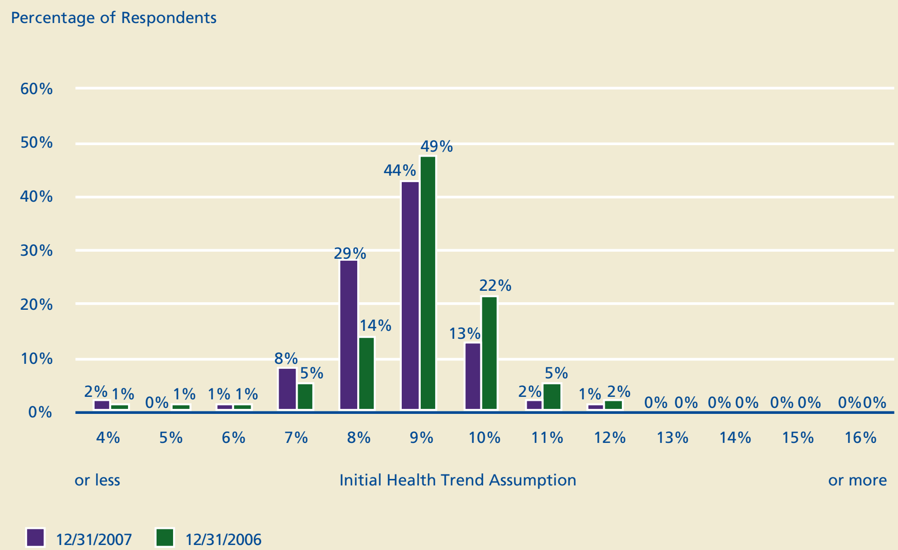


Exhibit 13. Change in Initial Health Trend Assumption

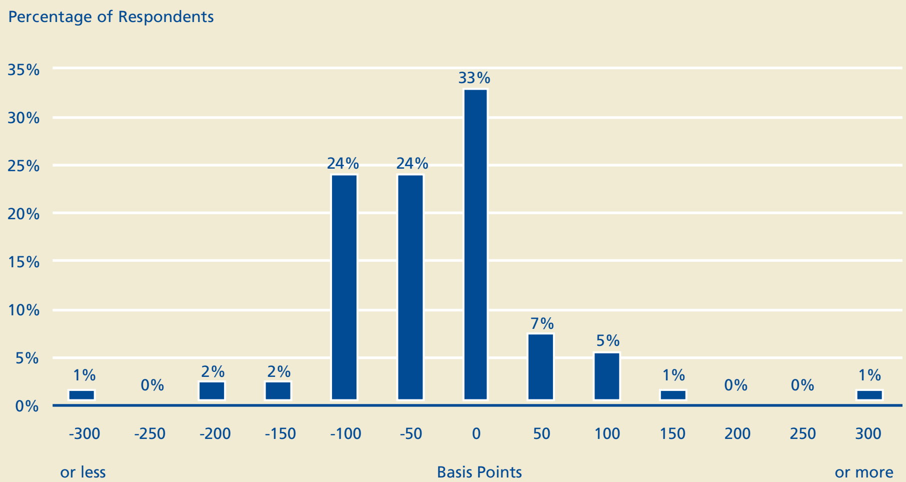


Exhibit 14 summarizes the ultimate health care cost trend disclosed as of December 31, 2007. At the end of 2007, the average ultimate Health Care Cost Trend rate was roughly 5.04 percent, approximately the same as disclosed at the end of the prior year.

Exhibit 15 compares the difference between the initial and ultimate trends at year-end 2007 compared with year-end 2006. Over the year, on average this difference decreased by about 36 basis points from 405 basis points to 369 basis points.

About the Survey

A number of factors influence each company as it selects the appropriate assumptions to measure its pension and benefits liabilities. This survey is intended to provide information regarding the assumptions disclosed by a wide range of companies and, as such, can provide an indication of the trends in the marketplace.

Exhibit 14. Ultimate Health Trend Assumption

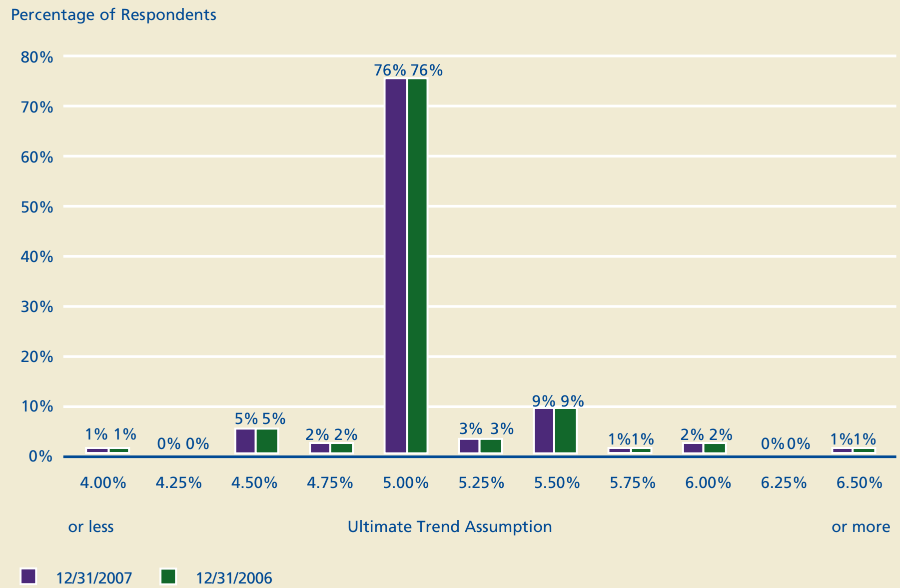
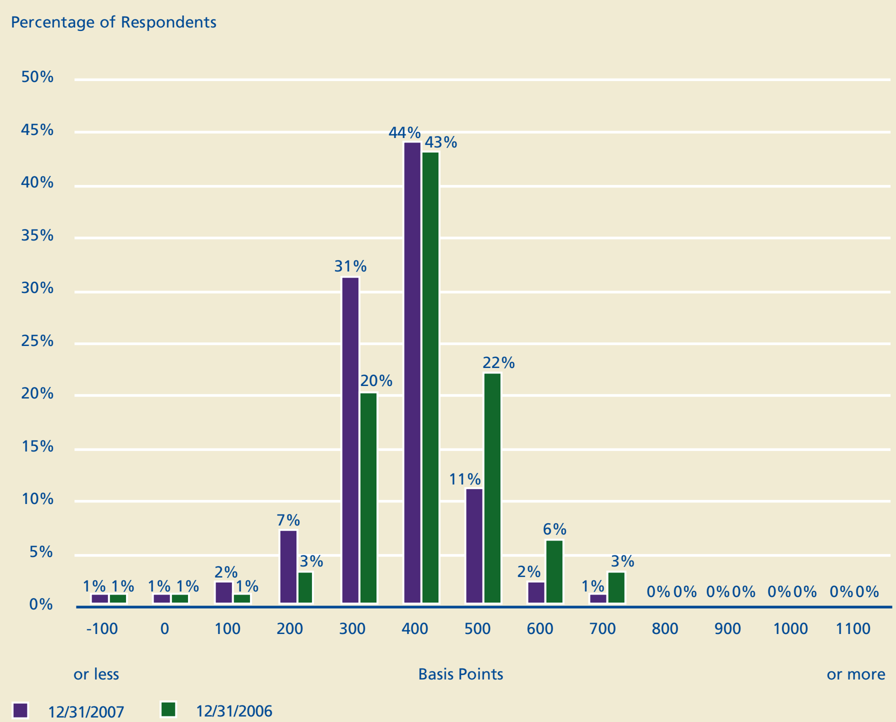


Exhibit 15. Difference Between Initial and Ultimate Health Trends



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PSC DOCKET NO. 10-237
DE PSC STAFF'S FOLLOW UP ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-172
Refer to the response to PSC-LA-21 and Mr. VonSteuben's direct testimony at page 7, lines 13-16. a. Does DPL's updated filing reflect the remaining gas specific CWIP balance of $963,382 as closed to Gas Plant in Service? If not, explain why not. If so, identify exactly where the $963,382 is reflected in the updated filing. b. Provide the corresponding amount of Accumulated Deferred Income Taxes (ADIT) and indicate whether DPL's updated test period rate base is offset by this ADIT amount. If not, explain fully why not.

RESPONSE:

a. Of the $963,382 identified by Mr. VonSteuben on page 7 of his Direct testimony, $589,404 was not placed in service as of June 30, 2010. As of August 31, 2010, $277,123 has not yet been placed into service. If the balance has not yet been placed into service, it remains in CWIP.
b. The Company has updated its deferred tax balance when it provided the 12+0 update ending June 2010.

Respondent: W. Michael VonSteuben

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-25
Regarding Schedule JCZ-13, please provide the Company's 2010 actuarial report when available.

RESPONSE:

See the attachment.

Respondent: Jay C. Ziminsky

Pepco Holdings, Inc.
PHI Retirement Plan

Actuarial Valuation Report FAS 87 and 158 Pension Cost for Fiscal Year Beginning January 1, 2010

August 31, 2010

TOWERS WATSON

Table of Contents

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Purpose and actuarial statement

As requested by Pepco Holdings, Inc (the Company), this report documents the results of an actuarial valuation of the PHI Retirement Plan (the Plan) formed through the merger of the Pepco General Retirement Plan with the Conectiv Retirement Plan on December 31, 2002. The primary purpose of this valuation is to determine the Net Periodic Benefit Cost/(Income) (Benefit Cost), in accordance with Statement of Financial Accounting Standard No. 87 (SFAS 87) for the fiscal year beginning January 1, 2010. It is anticipated that a separate report will be prepared for year-end disclosure purposes.

Accumulated other comprehensive income/(loss) amounts shown in the report are shown prior to adjustment for deferred taxes. Any such deferred tax allowance should be made in consultation with the Company's tax advisors and auditors.

This report is provided subject to the terms set out herein and in our engagement letter and the accompanying General Terms and Conditions of Business. This report is provided solely for the Company's use and for the specific purposes indicated above. It may not be suitable for use in any other context or for any other purpose.

Except where we expressly agree in writing, this report should not be disclosed or provided to any third party, other than as provided below. In the absence of such consent and an express assumption of responsibility, no responsibility whatsoever is accepted by us for any consequences arising from any third party relying on this report or any advice relating to its contents.

The Company may make a copy of this report available to its auditors, but we make no representation as to the suitability of this report for any purpose other than that for which it was originally provided and accept no responsibility or liability to the Company's auditors in this regard. The Company should draw the provisions of this paragraph to the attention of its auditors when passing this report to them.

In preparing these results, we have relied upon information and data provided to us orally and in writing by Pepco Holdings, Inc and other persons or organizations designated by Pepco Holdings, Inc. We have relied on all the data and information provided, including Plan provisions, membership data and asset information, as being complete and accurate. We have not independently verified the accuracy or completeness of the data or information provided, but we have performed limited checks for consistency.

The results summarized in this report involve actuarial calculations that require assumptions about future events. Pepco Holdings, Inc is responsible for the selection of the assumptions. We believe that the assumptions used in this report are within the range of possible assumptions that are reasonable for the purposes for which they have been used. However, other assumptions are also reasonable and appropriate and their use would produce different results.

In our opinion, all calculations are in accordance with requirements of applicable financial accounting standards, including SFAS 87, 88, 130, 132(R) and 158 (or the standards that supersede these statements under the FASB Accounting Standards Codification), and the procedures followed and the results presented are in conformity with applicable actuarial standards of practice. References in this report to specific financial accounting standards such as those named in this paragraph are intended to encompass standards that supersede the referenced statements under the FASB Accounting Standards Codification.

The undersigned consultants with actuarial credentials meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinions contained herein. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Delaware Inc.

Howard B. Simms, FSA, EA
Consulting Actuary
August 2010

Towers Watson

Ray N. Shaak, FSA, EA
Consulting Actuary
August 2010

Towers Watson

Katie L. Euston, ASA, EA
Consulting Actuary
August 2010

Towers Watson

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Section 1: Summary of key results

Benefit cost, assets & obligations

All monetary amounts shown in US Dollars

Fiscal Year Beginning		01/01/2010	01/01/2009
Benefit Cost/ (Income)	Net Periodic Benefit Cost/(Income)	64,072,078	95,252,818
	Immediate Recognition of Benefit Cost/(Income) due to Special Events	993,000	0
	Total Benefit Cost/(Income)	65,065,078	95,252,818
Measurement Date		**01/01/2010**	**01/01/2009**
Plan Assets	Fair Value of Assets (FVA)	1,499,682,010	1,122,723,052
	Market Related Value of Assets (MRVA)	1,499,682,010	1,122,723,052
	Return on Fair Value Assets during Prior Year	20.942%	(26.603%)
Benefit Obligations	Accumulated Benefit Obligation (ABO)	(1,627,483,744)	(1,594,054,710)
	Projected Benefit Obligation (PBO)	(1,741,735,045)	(1,727,163,597)
Funded Ratios	Fair Value of Assets to ABO	92.1%	70.4%
	Fair Value of Assets to PBO	86.1%	65.0%
Accumulated Other Comprehensive Income/(Loss)	Net Transition Obligation/(Asset)	0	0
	Net Prior Service Cost/(Credit)	419,271	501,562
	Net Loss/(Gain)	599,821,800	757,379,837
	Total Accumulated Other Comprehensive Income/(Loss)	600,241,071	757,881,399
Assumptions[1]	Discount Rate	6.400%	6.500%
	Expected Long-term Return on Plan Assets	8.000%	8.250%
	Rate of Compensation/Salary Increase[2]	5.000%	5.000%
Participant Data	Census Date	01/01/2010	01/01/2009

[1] Rates are expressed on an annual basis where applicable.
[2] Compensation increase rate based on an age-related salary scale that starts at 9.00%, decreases to 3.00%, and has an average of 5.00% over an employee's career.

Comments on results

There were three assumption changes this year: (1) The discount rate was changed from 6.50% last year to 6.40% this year, (2) the expected return on assets was changed from 8.25% last year to 8.00% this year, and (3) the mortality assumption was updated for the new IRS prescribed mortality table for 2010.

We have reflected the sale of Conectiv Energy Services (CES) on July 1, 2010. On this date, all CES union employees will terminate with the buyer assuming the cost of early retirement subsidies. CES management employees are also assumed to terminate on this date, except for a group of participants identified by PHI to stay through the end of 2010. Participant statistics included in this report are as of January 1, 2010; all CES employees were still active employees of PHI on this date and have been included in the active statistics reports here.

In association with the CES sale, all CES employees were fully vested and salaried employees within three years of retirement eligibility were awarded additional service and age bridging them to their earliest retirement eligibility age. These provisions resulted in one-time charges of $263,000 and $730,000, respectively.

The pension expense amount reflects the negotiated changes to the pension benefits between PHI and Local 1238, effective July 1, 2010.

Plan provisions and assumptions

Appendix A outlines the assumptions and methods used in the valuation.

Appendix B outlines our understanding of the principal provisions of the plan being valued. The discount rate of 6.40% was selected by PHI in consultation with Towers Watson Delaware Inc. We have used an expected return on plan assets of 8.00%. These assumptions are the most important ones in determining the annual expense requirement and appear reasonable for the 2010 valuation.

The effect of these changes is summarized below:

	Increase(Decrease) in:	
Change	PBO	Expense
1. Discount rate	$ 17,851,633	$ 518,959
2. Mortality assumption	2,543,886	412,023
3. Expected Return on Assets		3,603,226
4. Total	$ 20,395,519	$4,534,208

Participant information

Participant data used in the actuarial valuation are summarized below along with comparable information from the prior Census Date.

All monetary amounts shown in US Dollars

Measurement Date Census Date		01/01/2010 01/01/2010	01/01/2009 01/01/2009
Participating Employees[1]	Number	4,795	4,825
	Average Annual Plan Compensation/Salary (limited)	86,609	83,102
	Average Age	47.34	47.25
	Average Credited Service	18.76	18.89
Participants with Deferred Benefits	Number	2,892	2,946
	Average Annual Deferred Benefits	14,555	12,844
Participants Receiving Benefits	Number	4,767	4,732
	Average Annual Benefit Payments	15,198	15,226

[1] Conectiv Energy Services (CES) employees are included as Participating Employees at January 1, 2010.

Section 2: Accounting exhibits

2.1 Net balance sheet position

All monetary amounts shown in US Dollars

Measurement Date		01/01/2010	01/01/2009
A	**Development of Net Balance Sheet Position**[1]		
	1 Projected benefit obligation (PBO)	(1,741,735,045)	(1,727,163,597)
	2 Fair value of assets (FVA)	1,499,682,010	1,122,723,052
	3 Net balance sheet asset/(liability)	(242,053,035)	(604,440,545)
B	**Current and Noncurrent Allocation**[1]		
	1 Noncurrent liabilities	(242,053,035)	(604,440,545)
	2 Net balance sheet asset/(liability)	(242,053,035)	(604,440,545)
C	**Accumulated Benefit Obligation (ABO)**	(1,627,483,744)	(1,594,054,710)
D	**Accumulated Other Comprehensive Income/(Loss)**		
	1 Net transition obligation/(asset)	0	0
	2 Net prior service cost/(credit)	419,271	501,562
	3 Net loss/(gain)	599,821,800	757,379,837
	4 Accumulated other comprehensive income/(loss)[2]	600,241,071	757,881,399
E	**Assumptions and Dates**[3]		
	1 Discount rate	6.400%	6.500%
	2 Rate of compensation/salary increase[4]	5.000%	5.000%
	3 Expected long-term return on plan assets	8.000%	8.250%
	4 Census date	01/01/2010	01/01/2009

[1] Whether the amounts in this table that differ from those disclosed at year-end must be disclosed in subsequent interim financial statements should be determined.

[2] This is the pre-tax amount. The plan sponsor may need to tax adjust this amount and set up an offsetting deferred tax adjustment.

[3] Rates are expressed on an annual basis where applicable.

[4] Compensation increase rate based on an age-related salary scale that starts at 9.00%, decreases to 3.00% and has an average of 5.00% over an employees' career.

2.2 Summary of net balances

All monetary amounts shown in US Dollars

A Summary of Net Transition Obligation/(Asset)

Measurement Date Established	Original Amount	Net Amount at 01/01/2010	Amortization Amount in 2010	Effect of Curtailments	Effect of Settlements	Other Events
Total		0	0	0	0	0

B Summary of Net Prior Service Cost/(Credit)

Measurement Date Established	Original Amount	Net Amount at 01/01/2010	Amortization Amount in 2010	Effect of Curtailments		Other Events
01/01/2003	1,010,465	419,271	41,145	0		(378,126)[1]
07/01/2010[2]	(6,036,084)	-	(285,637)	0		0
Total		419,271	(244,492)	0		(378,126)

All monetary amounts shown in US Dollars

C Summary of Net Loss/(Gain)

	Net Amount at 01/01/2010	Amortization Amount in 2010	Experience Loss/(Gain)	Effect of Curtailments	Effect of Settlements	Other Events
	599,821,800	40,284,715	N/A	0	0	0

[1] New negative Prior Service Cost base established July 1, 2010 as a result of plan changes adopted during Local 1238 negotiations offset remaining unamortized amount of $378,126.
[2] Based established July 1, 2010 in connection with plan changes adopted during Local 1238 negotiations. Amortization payment shown for 2010 reflects half annual payment. Beginning January 1, 2011, annual amortization amount is (571,274).

2.3 Development of assets for benefit cost

All monetary amounts shown in US Dollars

		Fair Value	Market-Related Value
A	**Reconciliation of Assets**		
1	Plan assets at 01/01/2009	1,122,723,052	1,122,723,052
2	Investment return	248,564,166	248,564,166
3	Employer contributions	300,000,000	300,000,000
4	Plan participants' contributions	0	0
5	Benefits paid	(170,807,556)	(170,807,556)
6	Administrative expenses paid	(797,652)	(797,652)
7	Acquisitions/divestitures	0	0
8	Settlements	0	0
9	Termination benefits	0	0
10	Other	0	0
11	Plan assets at 01/01/2010	1,499,682,010	1,499,682,010
B	**Rate of Return on Invested Assets**		
1	Weighted invested assets	1,221,920,448	
2	Rates of return	20.942%	
C	**Investment Loss/(Gain)**		
1	Actual return	248,564,166	
2	Expected return (based on 2009 expense)	101,068,009	
3	Loss/(Gain)	(146,698,505)	

2.4 Summary and comparison of benefit cost

All monetary amounts shown in US Dollars

Fiscal Year Beginning		01/01/2010	01/01/2009
A	**Total Benefit Cost**		
1	Employer service cost	34,835,399	35,434,682
2	Interest cost	106,331,622	106,892,976
3	Expected return on assets	(117,135,166)	(101,068,009)
4	Subtotal	24,031,855	41,259,649
5	Net transition obligation/(asset) amortization	0	0
6	Net prior service cost/(credit) amortization	(244,492)	82,291
7	Net loss/(gain) amortization	40,284,715	53,910,878
8	Amortization subtotal	40,040,223	53,993,169
9	Net periodic benefit cost/(income)	64,072,078	95,252,818
10	Cost of SFAS88 events	993,000	0
11	Other adjustments	0	0
12	Total benefit cost	65,065,078	95,252,818
B	**Assumptions and Dates**[1]		
1	Discount rate	6.400%	6.500%
2	Long-term rate of return on assets	8.000%	8.250%
3	Rate of compensation/salary increase[2]	5.000%	5.000%
5	Measurement date	01/01/2010	01/01/2009
6	Census date	01/01/2010	01/01/2009
C	**Assets at Beginning of Year**		
1	Fair market value	1,499,682,010	1,122,723,052
2	Market-related value	1,499,682,010	1,122,723,052
D	**Cash Flow**	**Expected**	**Actual**
1	Employer contributions	100,000,000	300,000,000
2	Plan participants' contributions[3]	0	0
3	Benefits paid from Company cash	0	0
4	Benefits paid from plan assets[3]	154,150,234	170,807,556

[1] These assumptions were used to calculate Net Periodic Benefit Cost/(Income) as of the beginning of the year. Rates are expressed on an annual basis where applicable. For assumptions used for interim measurement periods, if any, refer to Appendix A.
[2] Compensation increase rate based on an age related salary scale that starts at 9.00%, decreases to 3.00% and has an average of 5.00% over an employee's career.
[3] Over the measurement year.

Section 3: Data exhibits

3.1 Plan participant data

All monetary amounts shown in US Dollars

Census Date		01/01/2010	01/01/2009
A	**Participating Employees**[1]		
	1 Number	4,795	4,825
	2 Total annual plan compensation/salary	415,290,902	400,968,352
	3 Average plan compensation/salary	86,609	83,102
	4 Average age (years)	47.34	47.25
	5 Average credited service (years)	18.76	18.89
	6 Average future working life (years)	10.566	10.8450
	7 Projected Benefit Obligation (PBO)	862,695,908	887,467,911
B	**Participants with Deferred Benefits**		
	1 Number	2,892	2,946
	2 Total annual pension	42,093,614	37,839,019
	3 Average annual pension	14,555	12,844
	4 Average age (years)	51.95	51.25
	5 Projected Benefit Obligation (PBO)	178,171,597	158,791,266
C	**Participants Receiving Benefits**		
	1 Number	4,767	4,732
	2 Total annual pension	72,447,605	72,049,432
	3 Average annual pension	15,198	15,226
	4 Average age (years)	71.73	71.64
	5 Projected Benefit Obligation (PBO)	700,867,540	680,904,420

[1] Census data is as of January 1, 2010 prior to the Conectiv Energy Services (CES) sale. All CES employees included with the sale are shown here as participating employees. Pre-CES sale total Expected Future Working Lifetime (EFWL) is 48,217; post-CES sale total EFWL is 45,031.

3.2 Age and service distribution of participating employees

Attained Age	Attained Years of Credited Service and Number												
	0	1	2	3	4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40 & Over	Total
Under 25	23	32	34	10	3	1	0	0	0	0	0	0	0	103
25-29	33	53	62	30	21	52	1	0	0	0	0	0	0	252
30-34	26	57	51	24	20	137	27	0	0	0	0	0	0	342
35-39	29	34	44	22	14	134	76	42	9	0	0	0	0	404
40-44	18	28	25	28	10	121	63	131	152	2	0	0	0	578
45-49	19	13	21	10	6	100	64	132	298	173	30	0	0	866
50-54	9	16	17	9	8	63	52	66	191	292	299	56	0	1,078
55-59	8	4	7	5	3	36	35	36	87	149	188	244	17	819
60-64	2	4	1	1	1	19	19	16	35	46	51	78	32	305
65-69	0	0	0	0	0	7	5	4	5	8	4	5	8	46
70 & over	0	0	0	0	0	0	2	0	0	0	0	0	0	2
Total	167	241	262	139	86	670	344	427	777	670	572	383	57	4,795 [1]

Average:	Age	47	Number of Participants:	Fully vested	3,902 [2]	Males	3,380
	Service	19		Partially vested	0	Females	1,415

Census data as of January 1, 2010

1 Ages and service totals for purposes of determining category are based on exact (not rounded) values.
2 Count of fully vested employees is as of January 1, 2010, prior to the CES-sale. As a result of the sale, employees in effected business units were immediately vested.

Appendix A

Statement of actuarial assumptions and methods

Plan Sponsor

Pepco Holdings, Inc

Discount Rate

6.400%

Expected Long-Term Return on Assets for 2010

8.000%

Price Inflation

3.250%

Compensation/Salary Increases

Salary increases for both expense and year-end disclosure were assumed to follow an age graded scale beginning with 9.00% at age 20 and decreasing to 3.00% at age 55 and later. The average increase over an employee's career is 5.00%. The following table shows the rates at sample ages:

Age	Salary Increase
20	9.00%
25	8.00%
30	7.00%
35	5.00%
40	4.50%
45	3.75%
50	3.50%
55	3.00%

Future Increases in Social Security

3.750%

Mortality

The IRS prescribed mortality tables for 2010 with separate tables for annuitants/non-annuitants, males/females.

Retirement – Pepco GRP and PHI Sub-Plans

The rates at which participants are assumed to retire by age are shown below:

Age	Reduced Retirement Benefits	Unreduced Retirement Benefits*
55	3.0%	13.0%
56	3.0	10.0
57	4.0	10.0
58	6.0	10.0
59	5.0	13.0
60	5.0	13.0
61	5.0	15.0
62	8.0	22.0
63	12.5	20.0
64	8.0	30.0
65	-	40.0
66	-	25.0
67	-	35.0
68	-	40.0
69	-	50.0
70	-	100.0

*An additional 10.0% is added to these rates in the first year of eligibility.

The rates shown under the Unreduced Retirement Benefits column (without the additional 10% in the first year of eligibility) are used for PHI sub-plan employees hired after 1/1/2005.

Retirement – Conectiv Sub Plans

Age	Cash Balance & Delmarva	ACE
55	10.0%	30.0%
56	7.5	20.0
57	7.5	20.0
58	7.5	25.0
59	7.5	20.0
60	25.0	30.0
61	25.0	20.0
62	30.0	50.0
63	20.0	30.0
64	25.0	30.0
65	100.0	100.0

Disability Rates

The rates at which participants are assumed to become disabled by age and gender are shown below:

Attained Age	Males	Females
25	.09%	.05%
30	.11	.09
35	.15	.13
40	.22	.20
45	.33	.30
50	.54	.47
55	.94	.76
60	1.36	.93

Withdrawal Rates (not due to disability retirement or mortality)

The rates at which participants are assumed to leave the Company by age are shown below:

Attained Age	Rate of Withdrawal
25	10.0%
30	7.6
35	5.7
40	4.5
45	3.6
50	2.8
55	2.4
60	2.8
64	3.7

Marriage

85% of employees are assumed to be married when eligible for retirement; males are assumed to be 3 years older than females.

Loading

None.

Actuarial Cost Method

The Projected Unit Credit Cost Method is used to determine the service cost and the projected benefit obligation for retirement, termination, and ancillary benefits. Under this method, a “projected accrued benefit” is calculated as of the beginning of the year and as of the end of the year for each benefit that may be payable in the future. The “projected accrued benefit” is based on the plan’s accrual formula and upon service as of the beginning or end of the year, but using final average compensation, social security benefits, etc., projected to the age at which the employee is assumed to leave active service. The projected benefit obligation is the actuarial present value of the “projected accrued benefits” as of the beginning of the year for employed participants and is the actuarial present value of all benefits for other participants. The service cost is the actuarial present value of the difference between the “projected accrued benefits” as of the beginning and end of the year.

Asset Valuation Method

The investments in the trust fund are valued on the basis of their fair market value.

Basic Employee Data

Results presented in this report were developed from data provided by PHI for its active, disabled, terminated, and retired participants and beneficiaries.

Amortization of Unrecognized Net Gain or Loss

Amortization of the unrecognized net gain or loss resulting from experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of Net Periodic Benefit Cost/(Income) for a year.

If, as of the beginning of the year, that unrecognized net gain or loss exceeds 10% of the greater of the projected benefit obligation and the market-related value of plan assets, the amortization is that excess divided by the average remaining service period of participating employees expected to receive benefits under the plan.

Amortization of Net Prior Service Cost/(Credit)

Amortization of net prior service cost/(credit) resulting from a plan change is included as a component of Net Periodic Benefit Cost/(Income) in the year first recognized and every year thereafter until such time as it is fully amortized. The annual amortization payment is determined in the first year as the increase in Projected Benefit Obligation due to the plan change divided by the average remaining service period of participating employees expected to receive benefits under the Plan.

Nature of Actuarial Calculations

The results documented in this report are estimates based on data that may be imperfect and on assumptions about future events. Certain plan provisions may be approximated or deemed insignificant and therefore are not valued. Assumptions may be made about participant data or other factors. Reasonable efforts were made in this valuation to ensure that items that are significant in the context of the actuarial liabilities or costs are treated appropriately, and not excluded or included inappropriately. We believe that the use of approximations in our calculations, if any, has not resulted in a significant difference relative to the results we would have obtained by using more detailed calculations.

Changes in Assumptions and Methods since Last Actuarial Valuation Report

The discount rate assumption is 6.400% as of January 1, 2010. It was 6.500% as of January 1, 2009.

The expected long-term rate of return on assets decreased from 8.25% as of January 1, 2009 to 8.00% as of January 1, 2010.

The mortality assumptions this year are the 2010 male and female annuitant mortality tables specified by the Pension Protection Act of 2006 (PPA). Last year’s assumptions were the 2009 PPA sex-distinct mortality tables.

Appendix B

Summary of principal plan provisions

Pepco General Retirement Plan

Plan Sponsor

Pepco Holdings, Inc.

Plan

Pepco General Retirement Plan

Effective Date and Most Recent Amendment

The plan was originally effective January 1, 1936. The last amendment was effective January 1, 2009 and it expanded the notice and consent period to 30 to 180 days from 30 to 90 days.

Plan Year

The twelve-month period ending 12/31.

Coverage and Participation

Prior to January 1, 2005: All employees are covered upon the attainment of age 21. No new entrants after December 31, 2004. New hires after December 31, 2004 will enter the Pepco Holdings, Inc. Pension Plan.

Credited Service

Service after attainment of age 21, with a maximum of 40 years.

Vesting Service

All service

Pensionable Earnings

Base pay

Normal Retirement Benefit

Normal Retirement: Age 65.

Normal Retirement Benefit: The annual normal retirement benefit is equal to 1-3/4% of the final 3-year average compensation less 1-1/4% of the primary Social Security Benefit payable at age 65, multiplied by years of Benefit Service.

Late Retirement Benefit

If retirement occurs after the normal retirement date, the late retirement benefit will be equal to the normal retirement benefit calculated using final 3-year average compensation and benefit service as of the late retirement date.

Full Early Retirement Benefit

Full Early Retirement: Age 55 and 30 years of Vesting Service.

Full Early Retirement Benefit: The normal retirement benefit accrued to early retirement date, plus an additional benefit to cease upon attainment of age 62 or commencement of Social Security benefits, whichever is earlier. The amount of additional benefit is based on age and years of Vesting Service at early retirement. The additional monthly benefit is $X times years of Vesting Service where X = Retirement Age – 50, but no greater than $10.

Early Retirement Benefit

Early Retirement: Age 55 and 10 years of Benefit Service.

Early Retirement Benefit: The normal retirement benefit accrued to early retirement date, reduced by 2% for each year such date precedes age 65.

Long Term Disability Benefit

Eligibility: Disabled after September 1, 1980 and eligible to receive benefits under the long-term disability group insurance plan.

Retirement Benefit: Commencing at age 65, the retirement benefit for a disabled employee is based on his final average salary at date of disability and all years of Benefit Service assuming employment continues to age 65.

Vested Benefits Upon Termination of Service

Employees who terminate employment after completing five years of continuous service receive the normal retirement benefit accrued to date of termination payable at age 65. The actuarial equivalent of the benefit payable at age 65 can be elected any time after age 55.

Death Benefits for Participants in Active Service

Preretirement -

Upon the death of an employee who has attained age 55 and completed 10 years of Benefit Service, the spouse will receive an income of one-half the amount of the employee's retirement benefit.

Upon the death of an employee who has completed five years of service and not yet attainted age 55 or a former employee with a deferred vested pension, the spouse will receive one-half the amount of the employee's accrued retirement benefit (actuarially reduced) when the participant would have reached age 55.

Postretirement -

Death benefits will be paid in accordance with the form of payment elected by retirees. Effective January 1, 1994, a retiree's benefit will be reinstated to the straight-life form if the beneficiary predeceases the retiree within the first 3 years after retirement.

Forms of Payment

The normal form of benefit is a life annuity. Participants married at retirement will receive an actuarially equivalent joint and survivor annuity unless they elect otherwise. A participant may elect an optional form, if the spouse consents, including ten-year certain and life, Social Security adjustment, or any actuarially equivalent joint and survivor annuity.

Changes in Plan Provisions since Last Actuarial Valuation

None.

Summary of principal plan provisions – Cash Balance Sub Plan

Plan Sponsor

Pepco Holdings, Inc.

Plan

Cash Balance Sub-Plan

Effective Date and Most Recent Amendment

Effective January 1, 1999. The last amendment was effective January 1, 2009 and provided for a 75% contingent annuitant option and also expanded the notice and consent period to 30 to 180 days from 30 to 90 days.

Plan Year

The twelve-month period ending 12/31.

Coverage and Participation

Prior to January 1, 2005: Each non-bargaining unit employee, as well as members of Local 210-5, who was a participant in one of the prior plans on December 31, 1998. All other non-bargaining unit employees shall become a participant on the Entry Date coincident with or next following the completion of one year of service. After December 31, 2004 Local 210-5 only. All other non-bargaining unit new hires after December 31, 2004 will enter the Pepco Holdings, Inc. Pension Plan.

Credited Service

Years and months of service under the elapsed time rule.

Vesting Service

All service.

Pensionable Earnings

Total pay.

Normal Retirement Benefit

Eligibility: Age 65.

Normal Retirement Benefit is equal to the lesser of a. or b.

a. Cash balance account equal to the sum of:
   (i) the initial account balance, (ii) pay credits, (iii) interest credits, and (iv) transition credits.
b. 650% of Final Average Compensation as of the determination date.

Employees are entitled to a minimum benefit equal to the benefit accrued under the prior plan provisions as of December 31, 1998. For Grandfathered employees, (age 50 or 20 or more years of service as of December 31, 1998) the benefit under the prior plan continues to accrue for 10 years.

Initial account balance is the single sum equivalent of the accrued benefit under the prior plan as of December 31, 1998.

For active participants, an annual pay credit is added to the account on the last day of each Plan Year. The amount of the credit is equal to the participant's annual compensation for the Plan Year multiplied by the Pay Crediting Rate. Pay crediting rate:

Participant's Age Attained in Plan Year	Pay Crediting Rate
Under 30	5.0%
30-34	6.0%
35-39	7.0%
40-44	8.0%
45-49	9.0%
50 and over	10.0%

For active participants, as well as terminated vested participants who have not begun receiving benefit payments, an annual interest credit is added to the account as of the end of each Plan Year. The amount of the interest credit is equal to the account balance as of the December 31 of the immediately preceding Plan Year multiplied by the Interest Crediting Rate for such Plan Year. For each Plan Year, the interest crediting rate is the 30-year Treasury Bond rate for the October immediately preceding the beginning of the Plan Year.

For active participants who were non-bargaining unit employees on December 31, 1998 and were credited with at least ten years of service as of January 2, 1999, an annual transition credit is added to the account as of the end of each Plan Year, beginning as of January 1, 1999. Transition credits will continue to be credited until the Plan Year in which the participant is credited with more than 35 years of service.

The amount of the credit is equal to the participant's annual compensation for the Plan Year multiplied by the Transition Crediting Rate. The Transition Crediting Rate is a percentage determined on the basis of the years of service credited to the participant as of January 2, 1999, as follows:

Participant's Years of Service as of January 2, 1999	Transition Crediting Rate
<10 years	0.0%
10-11 years	1.0%
12-15 years	2.0%
16-19 years	3.0%
20+ years	4.0%

The accrued benefit is the greater of the Payable Cash Balance, converted to an actuarially equivalent single life annuity or the minimum benefit stated as a life annuity.

A Grandfathered Employee is a prior non union or Local 210-5 plan participant who was an active employee on January 1, 1999 and who, as of December 31, 1998, either attained age 50 or is credited with 20 or more years of credited service.

Final average compensation for purposes of determining the 650% limit on the Payable Cash Balance is the average of the highest five consecutive calendar years of compensation. For purposes of calculating the grandfathered benefit, the highest consecutive 60 months for the Delmarva subplan and the highest 5 years out of the last 10 years for Ace.

Disability Retirement Benefit

Eligibility: On permanent disability, after completing 15 years of service. Disability Retirement Benefit:

On pre-65 disability, the lesser of: (i) cash balance account as of disability retirement date projected to normal retirement age and credited with 4% interest each Plan Year, converted to an actuarially equivalent single life annuity; (ii) 650% of Final Average Compensation as of disability retirement date, converted to an actuarially equivalent single life annuity.

On post-65 disability, the accrued benefit.

Vested Benefits Upon Termination of Service

Eligibility: Terminate for reasons other than death or retirement after completing 5 years of service.

Deferred Vested Benefit: Accrued Benefit as of termination date, payable immediately.

Death Benefits for Participants in Active Service

The Payable Cash Balance as of the date of death payable as an immediate lump sum or, for a beneficiary who is the surviving spouse of a participant, the Payable Cash Balance converted to an actuarially equivalent single life annuity payable immediately.

Forms of Payment

Pension benefits are paid as a life annuity if the participant has no spouse as of the date payments begin. Otherwise, benefits are paid in the form of a reduced 50% contingent annuitant option or, if the participant elects and the spouse consents, another actuarially equivalent optional form offered by the plan. Optional forms are 100% contingent annuitant option, 75% contingent annuitant option, life annuity or lump sum. Level income options or a 25% contingent annuitant option are also available for participants who were part of the ACE plan prior to January 1, 1999.

Changes in Plan Provisions Since Last Actuarial Valuation

None.

Summary of principal plan provisions – Delmarva Sub Plan

Plan Sponsor

Pepco Holdings, Inc.

Plan

Delmarva Sub Plan

Effective Date and Most Recent Amendment

Effective January 1, 1999. The last amendment was effective January 1, 2009 and provided a 75% contingent annuitant option and also expanded the notice and consent period to 30 to 180 days from 30 to 90 days.

Plan Year

The twelve-month period ending 12/31.

Coverage and Participation

On or after January 1, 2005: All employees of Local 1238 and Local 1307. Grandfathered Delmarva heritage non-bargaining unit employees.

Participation date is date of employment for all covered employees who were participants of the prior plan as of December 31, 1998. Otherwise, date coincident with or next following completion of one year of service.

Credited Service

Years and months of service under the elapsed time rule.

Vesting Service

All service.

Pensionable Earnings

Total pay.

Normal Retirement Benefit

Eligibility: Age 65 and completion of 5 years of service.
Benefit: The Pension Benefit is:
1.60% of Average Annual Earnings times years of service. However, not less than the maximum of: The lesser of (i) $1,000 or (ii) $100 times years of service.

Average Annual Earnings is the average of the highest 60 consecutive months of total cash compensation.

Average Social Security Earnings Base is the average of the taxable wage bases in effect for each calendar year during the 35-year period ending on the last day of the calendar year in which the employee terminates employment.

Early Retirement Benefit

Eligibility: Age 55 and 15 years of service.

Benefit: The Pension Benefit accrued to early retirement date, reduced as follows for early commencement:

Age at Retirement	< 20 Years Service	>= 20 Years of Service
60-64	95%	100%
59	95%	95%
58	90%	90%
57	85%	85%
56	80%	80%
55	76%	76%

Late Retirement Benefit

Pension Benefit determined as of actual retirement date.

Disability Retirement Benefit

Eligibility: 15 years of service and provision of satisfactory medical evidence of disability.

Benefit: Pension benefit determined as of date of disability.

Vested Benefits Upon Termination of Service

Eligibility: Terminate for reasons other than death or retirement after 5 years of service.

Benefit: Pension Benefit determined as of termination date, payable at 65. If participant has completed 15 years of service at termination, an actuarially reduced benefit may be paid at an earlier date, but not before age 55. Effective March 1, 1996, a vested terminated employee may elect to receive a lump sum payment in lieu of an annuity within 90 days of receipt of notice from the plan administrator.

Death Benefits for Participants in Active Service

Eligibility: Death while eligible for deferred vested, early, normal, or deferred retirement benefits with a surviving spouse.

Benefit: Preretirement Spouse Benefit.

Forms of Payment

Monthly pension benefits will be paid as described above if the participant has no spouse as of the date payments commence, unless the participant elects another actuarially equivalent optional form offered by the plan. Otherwise, benefits will be paid in the form of an unreduced 50% contingent annuity or, if the participant elects and the spouse consents, another actuarially equivalent optional form offered by the plan, including a 75% contingent annuitant option.

Changes in Plan Provisions Since Last Actuarial Valuation

As a result of the collective bargaining agreement negotiated between PHI and Local 1238, the following changes will be implemented with respect to Local 1238 participants:

- 50% and 75% joint and survivor options will be actuarially equivalent to the single life annuity; employees with 30 or more years of service at 1/1/2011 are unaffected.
- A retiree's benefit will be reinstated to the straight-life form if the beneficiary predeceases the retiree within the first three years of retirement.
- The definition of final average earnings will change to base pay earnings; employees with 25 or more years of service at 1/1/2011 will be able to include 100% of non-base earnings. Employees with 20 to 25 years of service at 1/1/2011 will be able to include 75% of non-base earnings.
- Employees hired on or before 8/31/2010 and who have less than 20 years of service at 1/1/2011 will be able to retire with an unreduced benefit upon attainment of age 55 with 30 years of service.
- The lump sum option will be eliminated for terminated vested employees.
- Lump sums will be calculated with the PPA interest rates. This will be phased in over five years: 10%/20%/50%/70%/100%.

Summary of principal plan provisions – ACE Sub Plan

Plan Sponsor

Pepco Holdings, Inc.

Plan

ACE Sub Plan

Effective Date and Most Recent Amendment Effective January 1, 1999.

The last amendment was effective January 1, 2009 and provided a 75% contingent annuitant option and also expanded the notice and consent period to 30 to 180 days from 30 to 90 days.

Plan Year

The twelve-month period ending 12/31.

Coverage and Participation

On or after January 1, 2005: All employees of Local 210. Grandfathered non-bargaining unit employees.

Participation date is date of employment for all covered employees who were participants of the prior plan as of December 31, 1998. Otherwise, date coincident with or next following completion of one year of service.

Credited Service

A year of benefit service is credited in each Plan Year in which a participant completes at least 2,080 hours of service, beginning on date of employment. For any year in which the participant has less than 2,080 hours of service, a pro rata portion of service will be credited.

Vesting Service

A Plan Year in which an employee completes at least 1,000 hours of service.

Pensionable Earnings

Total pay excluding overtime and certain incentive compensation.

Normal Retirement Benefit

Eligibility: First day of the month nearest the participant's 65th birthday.

Benefit: The Pension Benefit is:

1.60% of Average Annual Earnings for each year of benefit service, up to 30 years for those hired after January 1, 1989.

However, not greater than the maximum of:
(a) $25,000 or (b) 66 2/3% of Average Annual Earnings.

Average Annual Earnings is the average of the highest 5 consecutive years out of the last 10 years of compensation, excluding overtime and certain incentive compensation.

Early Retirement Benefit

Eligibility: On or after attaining age 55 with 5 years of service.

Benefit: Pension Benefit determined as of early retirement date.

Late Retirement Benefit

Eligibility: Any first day of month after Normal Retirement Date.

Benefit: Pension Benefit determined as of actual retirement date.

Disability Retirement Benefit

Eligibility: 15 years of service, disabled for 12 months, and become entitled to receive Disability benefits under the Federal Social Security Act.

Benefit: Pension Benefit determined as of date of disability.

Vested Benefits Upon Termination of Service

Eligibility: Termination for reasons other than death or retirement after 5 years of service.

Benefit: Pension Benefit determined as of termination date, payable on unreduced basis as early as age 55.

Death Benefits for Participants in Active Service

Eligibility: Death while eligible for deferred vested, early, normal, or late retirement benefits, with surviving spouse.

Benefit: Preretirement Spouse Benefit is payable when the participant would have reached age 55.

Forms of Payment

The normal form of benefit is a life annuity. Participants married at retirement will receive an actuarially equivalent 50% joint and survivor annuity unless they elect otherwise. A participant may also elect an optional form, if the spouse consents, including 25%, 33 1/3%, 50%, 66 2/3%, 75%, or 100% joint and survivor, a level income option or a lump sum, payable on or after age 55.

Changes in Plan Provisions Since Last Actuarial Valuation

None.

Summary of principal plan provisions – PHI Sub Plan

Plan Sponsor

Pepco Holdings, Inc.

Plan

PHI Sub Plan

Effective Date and Most Recent Amendment Effective January 1, 2005.

The last amendment was effective January 1, 2009 and it expanded the notice and consent period to 30 to 180 days from 30 to 90 days.

Plan Year

The twelve-month period ending 12/31.

Coverage and Participation

All regular full-time and part-time management and Local 1900 employees hired on or after January 1, 2005 are covered as of the first day of the month following their date of hire.

Benefit Service

Service after becoming a member, with a maximum of 30 years.

Vesting Service

All service.

Pensionable Earnings

Base pay.

Normal Retirement

Normal Retirement: Later of age 65 or 5 years of service. Based on the greater / greatest of the following formulas

Benefit

Normal Retirement Benefit: The annual normal retirement benefit is equal to 1.3% of the final 5-year average compensation multiplied by years of Benefit Service.

Full Early Retirement

Full Early Retirement: Age 62 and 20 years of Vesting Service.

Benefit Full Early Retirement Benefit: The normal retirement benefit accrued to early retirement date.

Early Retirement Benefit

Early Retirement: Age 55 and 10 years of Benefit Service.

Early Retirement Benefit: The normal retirement benefit accrued to early retirement date, reduced by 3% for each year such date precedes age 65. If the member has at least 20 years of Vesting Service at Early Retirement Date, the accrued benefit is reduced by 3% for each year such date precedes age 62.

Late Retirement Benefit

If retirement occurs after the normal retirement date, the late retirement benefit will be equal to the normal retirement benefit calculated using final 5-year average compensation and benefit service as of the late retirement date.

Long Term Disability Benefit

Eligibility: Eligible to receive benefits under the long-term disability group insurance plan.

Retirement Benefit: Commencing at age 65, the retirement benefit for a disabled employee is based on his final average salary at date of disability and all years of Benefit Service assuming employment continues to age 65.

Vested Benefits Upon Termination of Service

Employees who terminate employment after completing five years of continuous service receive the normal retirement benefit accrued to date of termination payable at age 65. The actuarial equivalent of the benefit payable at age 65 can be elected any time after age 55.

Death Benefits for Participants in Active Service

Preretirement -

Upon the death of an employee who has attained age 55 and completed 10 years of Benefit Service, the spouse will receive an income of one-half the amount of the employee's retirement benefit.

Upon the death of an employee who has completed five years of service and not yet attainted age 55 or a former employee with a deferred vested pension, the spouse will receive one-half the amount of the employee's accrued retirement benefit reduced for 50% J&S form of payment and actuarially reduced for early retirement based on when the participant would have reached age 55.

Postretirement -

Death benefits will be paid in accordance with the form of payment elected by retirees. A retiree's benefit will be reinstated to the straight-life form if the beneficiary predeceases the retiree within the first 3 years after retirement.

Forms of Payment

The normal form of benefit is a life annuity. Participants married at retirement will receive an actuarially equivalent joint and survivor annuity unless they elect otherwise. A participant may elect an optional form, if the spouse consents, including a single sum distribution if the actuarial value of the annuity is less than $20,000 or any actuarially equivalent 25%, 50%, 75%, or 100% joint and survivor annuity.

Changes in Plan Provisions Since Last Actuarial Valuation

None.

Appendix C –

Allocation of Expense Amongst Business Units

Net Periodic Pension Cost	DPL 1000	ACE 1500	Pepco 7000	PES 7700	Svc Co 9000	CDG 3010	CAG 3016	CTS 5700	Consolco 9950	Total
Service Cost	7,691,021	5,159,530	7,349,316	199,315	13,538,730	588,480	295,171	13,836	-	34,835,399
Interest Cost	25,987,235	12,635,539	42,583,493	478,950	21,714,204	1,828,662	1,038,905	64,634	-	106,331,622
Expected ROA	(29,163,924)	(13,949,073)	(50,550,971)	(261,361)	(21,434,917)	(1,883,923)	119,468	(10,465)	-	(117,135,166)
Amortization of:										
- Unrecognized (Gain)/Loss	13,277,943	5,663,265	22,277,373	277,525	7,848,566	363,700	539,702	19,100	(9,982,459)	40,284,715
- Prior Service Cost	406,953	336,347	-	-	231,206	87,390	27,632	1,892	(1,335,912)	(244,492)
- Unrecognized Transition Amount	-	-	-	-	-	-	-	-	-	-
- Total	13,684,896	5,999,612	22,277,373	277,525	8,079,772	451,090	567,334	20,992	(11,318,371)	40,040,223
Pension Expense (Hist. Basis)	18,199,228	9,845,608	21,659,211	694,429	21,897,789	984,309	2,020,878	88,997	(11,318,371)	64,072,078
One Time Charge Associated with CES Sale										
Immediate Vesting	-	-	-	-	206,000	26,000	31,000	-	-	263,000
Bridge to Early Retirement	-	-	-	-	730,000	-	-	-	-	730,000

Appendix D –

Development of Loss/(Gain)

Pepco Holdings, Inc. Retirement Plan

Development of Loss (Gain) for Disclosure/Expense

1.	Expected PBO at December 31, 2009	
	a. PBO at January 1, 2009	$ 1,727,163,597
	b. Current Service Cost	35,434,682
	c. Interest Cost	106,892,976
	d. Benefit Payments during 2009	(170,807,556)
	e. Loss (Gain) Attributable to Variable Annuity Adjustment	2,628,806
	f. Expected PBO at December 31, 2009 [Sum of 1.a. through 1.e.]	1,701,312,505
2.	Effect of Assumption Changes on PBO	
	a. Change in Discount Rate to 6.40%	17,851,663
	b. Change in Mortality Assumption	2,543,886
	c. Total Effect of Assumption Changes [Sum of 2.a. through 2.b.]	20,395,549
3.	Expected PBO at January 1, 2010 [1.f. + 2.c.]	1,721,708,054
4.	Actual PBO at January 1, 2010	1,741,735,045
5.	Liability Loss (Gain) for 2009 Attributable to Data [4. – 3.]	20,026,991
6.	Total Liability Loss (Gain) for 2009 [1.e.+ 2.c.+ 5.]	43,051,346
7.	Expected Trust Fund Assets at December 31, 2009	
	a. Trust Fund Assets at January 1, 2009	1,122,723,052
	b. PHI Contributions	300,000,000
	c. Expected Return on Assets	101,068,009
	d. Trust Fund Benefit Payments during 2009	(170,807,556)
	e. Expected Trust Fund Assets at December 31, 2009 [Sum of 7.a. through 7.d.]	1,352,983,505
8.	Trust Fund Assets at December 31, 2009	1,499,682,010
9.	Asset Loss (Gain) for 2009 [7.e. – 8.]	(146,698,505)
10.	Total Loss (Gain) for 2010 [6. + 9.]	(103,647,159)
11.	Unrecognized Loss from Prior Years	757,379,837
12.	Amount Amortized during 2009	53,910,878
13.	Unrecognized Loss (Gain) for Expense at January 1, 2010 [10. + 11. - 12.]	599,821,800

Appendix E

PHI Nonqualified Plans

Pepco Holdings, Inc. SERPs	PHI Nonqualified Plan	Board of Directors Plan
Reconciliation of Funded Status at January 1, 2010		
Accumulated benefit obligation	$(66,916,891)	$(327,435)
Projected benefit obligation	(68,243,423)	(327,435)
Plan assets at fair value	-	-
Excess of plan assets over PBO	(68,243,423)	(327,435)
Unrecognized net loss	26,105,497	31,872
Prior service cost	(439,167)	-
Unrecognized transition obligation	-	-
Prepaid/(accrued)	(42,577,093)	(295,563)
Net Periodic Pension Cost for 2010		
Service cost	436,489	-
Interest cost	4,180,840	17,820
Expected return on plan assets	-	-
Amortization payments		
Unrecognized loss (gain)	1,913,689	-
Prior service cost	(81,614)	-
Unrecognized transition amount	-	-
Total	1,832,075	-
Net periodic pension cost (PHI basis)	6,449,404	17,820
Historical Basis	6,610,698	17,820
Consolidating Entry	161,294	-

Key Actuarial Assumptions

Discount Rate	6.40%
Salary Increase Rate	Age graded scale starting at 9.0% at age 20 and decreasing to 3.0%. Average increase over an employee's career is 5.0%.
Demographic Assumptions	Same as for Qualified Plan valuation.

Appendix E

PHI Nonqualified Plans

Pepco Holdings, Inc. SERPs
Allocation of FAS 87 Expense for FY 2010*

	PCI	Pepco	ACE	DPL	Service Co	CSI II	Total Plan
Service Cost:	6,724	105,478	5,644	33,918	281,854	2,871	436,489
Interest Cost:	64,406	1,010,305	54,062	324,874	2,699,689	27,504	4,180,840
Return on Assets:							
Amortization of:							
Transition Obligation (asset)							
Prior Service Cost (credit)	(1,257)	(19,922)	(1,055)	(6,342)	(52,701)	(537)	(81,614)
Losses (gains)	29,480	462,445	24,846	148,704	1,235,724	12,590	1,913,689
Net periodic pension cost (PHI basis)	99,353	1,558,506	83,397	501,154	4,164,566	42,428	6,449,404
Consolidating Entry Amortization			17,391	104,507	30,549	8,847	161,294
Historical Basis	99,353	1,558,506	100,788	605,661	4,195,115	51,275	6,610,698
Board of Directors Plan		12,735	5,085				17,820

*Expense for the non-qualified plans is allocated by PBO among actives and inactives. Conectiv inactives are explicitly assigned to the appropriate group.

Appendix E – PHI Nonqualified Plans cont.

PHI COMBINED EXECUTIVE RETIREMENT PLAN
SUPPLEMENTAL BENEFIT STRUCTURE

Plan Sponsor

Pepco Holdings, Inc.

Effective Date and Most Recent Amendment

The plan was originally effective February 17, 1983. The last amendment was October 2008, which incorporated legislation from Section 409A of the Internal Revenue Code.

Applicable Defined Benefit Pension Plan

The principal defined benefit pension plan of PEPCO Holdings or one of its subsidiaries in which the Participant participates (ADBPP).

Coverage and Participation

Any employee of any PEPCO Holdings subsidiary as designated by the CEO.

Pensionable Earnings

Compensation as defined by the ADBPP increased by any deferred compensation that was excluded from the ADBPP definition. The Pensionable Earnings are determined without regard to any dollar limitation under the Internal Revenue Code on the amount of compensation that may be considered in determining benefits.

Retirement Benefits

Amount: The difference, if any, between (i) and (ii) as follows:

i. The amount of the benefits to which the Participant would be entitled under the provisions of the ADBPP and, if applicable, the Conectiv Supplemental Executive Retirement Plan with the amount of compensation as defined in Pensionable Earnings. Benefits under this plan are not limited by Section 415 of the Internal Revenue Code.

ii. The amount of benefits, if any, to which the Participant is entitled to under the ADBPP.

To the extent that a cost of living adjustment is made to benefits payable under the ADBPP, a comparable and proportional adjustment will be made to benefits payable under this plan.

Timing and Form of Payment: Except for 'Specified Employees' (defined in Section 409A(a)(2A)(B)(i) of the Internal Revenue Code), the monthly benefit provided under this plan shall commence as of the first of the month on which the Participant begins receipt of benefits under the ADBPP and shall continue as long as benefits are payable under the ADBPP. 'Specified Employees' shall have a commencement date that is delayed six months after the separation from service. The form of benefit paid under this plan shall be the same form elected by the Participant with respect to benefits paid under the ADBPP. No other benefit options are available under this plan.

Vesting: The Supplemental Benefit shall vest when the Participant would be vested under the terms and conditions of the ADBPP.

Early Receipt: In the event benefits under the ADBPP are paid prior to Normal Retirement Date, the Supplement Benefit payable hereunder shall be adjusted by use of the same methodology as is then in effect to adjust the benefit payable under the ADBPP to reflect commencement of benefits prior to a Participant's Normal Retirement Date.

Death Benefits

Eligibility: The terms of the ADBPP shall govern the eligibility for benefits under this plan.

Amount: The difference between (i) and (ii) as follows:

i. The amount of the survivor benefit to which the surviving spouse would be entitled under the provisions of the ADBPP with the amount of compensation as defined in Pensionable Earnings. Benefits under this plan are not limited by Section 415 of the Internal Revenue Code.

ii. The amount of benefit to which the surviving spouse is entitled to under the ADBPP.

Timing and form of payment: The terms of the ADBPP shall govern the timing and form of payment of the Supplemental Benefit to the surviving spouse. Benefits shall begin when benefits commence to such surviving spouse under the ADBPP and shall continue for as long as benefits are payable to such surviving spouse under such plan.

Appendix E – PHI Nonqualified Plans cont.

PHI COMBINED EXECUTIVE RETIREMENT PLAN
EXECUTIVE PERFORMANCE SUPPLEMENTAL RETIREMENT BENEFIT STRUCTURE

Plan Sponsor

Pepco Holdings, Inc.

Effective Date and Most Recent Amendment

The plan was originally effective January 27, 1994. The last amendment was October 2008, which incorporated legislation from Section 409A of the Internal Revenue Code.

Applicable Defined Benefit Pension Plan The principal defined benefit pension plan of PEPCO Holdings or one of its subsidiaries in which the Participant participates (ADBPP).

Coverage and Participation

Any employee of any Pepco Holdings subsidiary as designated by the CEO. An employee shall cease to be a Participant in this Plan and shall not be entitled to any benefits hereunder if the employment of such employee is terminated for any reason, other than death, before the later of (i) the date the employee attains age 59, or (ii) the date the employee first attains either his Early Retirement Date or his Normal Retirement Date under the ADBPP. Due to the merger with Conectiv on August 1, 2002, certain participants who were under the age of 59 became vested under Section 3.7 - Payment of Benefits Upon Change in Control."

In order to receive benefits under the Plan, a Participant must not have incurred a forfeiture of benefits under (i) or (ii) above and must have been an Eligible Executive within the 12 months immediately preceding his actual retirement under the ADBPP, and either (a) have held such position for at least a 5-year period, or (b) have attained age 65.

Pensionable Earnings

Compensation as defined by the ADBPP increased by any deferred compensation that was excluded from the ADBPP definition, and also increased by the average of the three highest incentive awards within the five consecutive years immediately preceding the Participant's retirement. The Pensionable Earnings are determined without regard to any dollar limitation under the Internal Revenue Code on the amount of compensation that may be considered in determining benefits. Certain executives receive additional time vesting awards under the SERP.

Special Benefits Eligibility

As designated by the CEO

Amount: Additional benefits determined with imputed years of benefit service as provided by individual employment agreements.

Retirement Benefits

Amount: The difference, if any, between (i) and (ii) as follows:

i. The aggregate amount of the benefits to which the Participant would be entitled under the provisions of the ADBPP, the provisions of the Supplemental Executive Retirement Plan (SERP), and the provisions of the Supplemental Benefit Plan (SBP) with the amount of compensation as defined in Pensionable Earnings. Benefits under this plan are not limited by Section 415 of the Internal Revenue Code.

ii. The amount of benefits, if any, to which the Participant is entitled to under the ADBPP, SERP and the SBP.

To the extent that a cost of living adjustment is made to benefits payable under the ADBPP, a comparable and proportional adjustment will be made to benefits payable under this plan. Certain executives receive additional time vesting awards under the SERP (this benefit is excluded from this valuation).

Timing and Form of Payment: Except for 'Specified Employees' (defined in Section 409A(a)(2A)(B)(i) of the Internal Revenue Code), the monthly benefit provided under this plan shall commence as of the first of the month on which the Participant begins receipt of benefits under the ADBPP and shall continue as long as benefits are payable under the ADBPP. 'Specified Employees' shall have a commencement date that is delayed six months after the separation from service. The form of benefit paid under this plan shall be the same form elected by the Participant with respect to benefits paid under the ADBPP. No other benefit options are available under this plan.

Death Benefits

Eligibility: In order to receive death benefits under this plan, a surviving spouse must have been legally married to the Participant for at least one year prior to the Participant's death, and the sum of actual years of Benefit Service and constructive years of Benefit Service granted under the SERP must equal at least 10 years.

Amount: The difference, if any, between (i) and (ii) as follows:

i. The aggregate amount of the surviving spouse benefits to which the surviving spouse would be entitled under the provisions of the ADBPP, SERP, and the SBP with the amount of compensation as defined in Pensionable Earnings. Benefits under this plan are not limited by Section 415 of the Internal Revenue Code.

ii. The amount of benefits, if any, to which the surviving spouse is entitled to under the ADBPP, SERP, and the SBP.

Timing and form of payment: Benefits shall commence as of the first of the month on which such surviving spouse begins receipt of death benefits under the ADBPP and shall continue for as long as benefits are payable to such surviving spouse under such plan.

Glossary

Accumulated Benefit Obligation

This is the same as the Projected Benefit Obligation except that it is based on current and past compensation levels instead of future compensation levels.

Actuarial Gain or Loss

From one year to the next, if the experience of the plan differs from that anticipated using the actuarial assumptions, an actuarial gain or loss occurs. For example, an actuarial gain would occur if the assets in the trust earned 12% for the year while the expected long-term rate of return on assets used in the valuation was 8%.

Additional Minimum Liability

If a plan has a minimum liability, the sponsor may be required to post a liability on the balance sheet in addition to the accrued/(prepaid) benefit cost already recorded. If the Accumulated Benefit Obligation exceeds the fair value of assets, the plan has a minimum liability equal to the excess. If there is a minimum liability and it exceeds the Accrued/(Prepaid) Benefit Cost, the difference is called the Additional Minimum Liability and the accrued benefit liability equals the minimum liability.

Funded Status

This is the excess/(shortfall) of the fair value of plan assets over the Projected Benefit Obligation.

Prepaid/(Accrued) Benefit Cost

The sponsor's balance sheet asset/(liability) entry, the net recognized amount, is the sum of the cumulative excess of contributions to the plan over net periodic benefit costs and other plan-related charges to income due either to business combination or accelerated recognition pursuant to SFAS 88. The difference between this account and the Funded Status is the unrecognized net loss/(gain) and prior service costs.

Projected Benefit Obligation

Computed in accordance with SFAS 87, this quantity is the actuarial present value of all benefits attributed by the plan's benefit formula to service rendered prior to the measurement date. It is measured using an assumption as to future compensation levels when the benefit formula is based on future compensation levels.

Service Cost

Computed in accordance with SFAS 87, this component of the net periodic benefit cost is the actuarial present value of benefits attributed by the plan's benefit formula to services rendered by employees during the period over which the net periodic benefit cost is incurred. It is measured using an assumption as to future compensation levels when the benefit formula is based on those future compensation levels.

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-28
Provide a ten-year history of pension expense booked and the actual cash contributions made to the Company's pension plan for each year.

RESPONSE:

A. See below. These costs reflect DPL's total Pension costs that are either capitalized or expensed.

Year	**(000's) Total DPL Amount**
1999	(31,663)
2000	(43,839)
2001	(18,618)
2002	(10,248)
2003	(2,634)
2004	(9,256)
2005	(8,531)
2006	(6,580)
2007	(6,179)
2008	(6,033)
2009	13,438
2010	18,199

DPL made a cash contribution to the pension fund of $10 million in 2009.

Respondent: Jay C. Ziminsky

PSC DOCKET NO. 10-237
DE PSC STAFF'S FIRST SET OF ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-111
Does DPL have any projections of pensions, OPEBs and uncollectibles beyond 2010? If not, explain fully why not. If so, provide the amounts for each year beyond 2010 for which DPL has projections.

RESPONSE:
DPL does not have pension and OPEB projections beyond 2010 at this time. PHI just received the 2010 actual expense reports for pension and OPEB and future projections will depend on year-end discount rate and asset return.

DPL does not have any projections of uncollectible expense beyond 2010. DPL expects the current level of uncollectible expense, approximately 1% of total billed revenue, to continue into at least 2011.

Respondent: Jay C. Ziminsky

IN THE MATTER OF THE PETITION OF DELMARVA POWER & LIGHT COMPANY FOR AUTHORIZATION TO DEFER CERTAIN CHANGES TO THE COMPANY'S FINANCIAL STATEMENTS RESULTING FROM THE IMPACT OF RECENT ECONOMIC DEVELOPMENTS ON PENSION COSTS

**PSC DOCKET NO. 09-182
SECOND DATA REQUEST TO DELMARVA
FROM THE PSC STAFF**

PSC 2-6. Referring to Delmarva's response to PSC 1-10, please provide an estimate of the 2009 pension expense that will be deferred if Delmarva's Petition is granted. Please provide separate estimates for the Delaware electric and gas divisions.

Response:

Please refer to the table below.

(1) Line No.	(2) Item	(3) DE Electric Pension Expense	(4) DE Gas Pension Expense	(5) Total
1	2007	($54,401)	($127,834)	$ (182,235)
2	2008	$43,214	($42,423)	$ 791
3	2009	$8,001,610	$3,927,053	$ 11,928,664
4				
5	Average	$2,663,474	$1,252,266	$ 3,915,740
6				
7	Proforma proposed	$8,001,610	$3,927,053	$ 11,928,664
8				
9	Adjustment to Company (Average less Proforma	($5,338,136)	($2,674,788)	$ (8,012,924)
10	proposed)			
11				
12	Rate Base for Deferred Amount	$5,338,136	$2,674,788	$ 8,012,924

IN THE MATTER OF THE PETITION OF DELMARVA POWER & LIGHT COMPANY FOR AUTHORIZATION TO DEFER CERTAIN CHANGES TO THE COMPANY'S FINANCIAL STATEMENTS RESULTING FROM THE IMPACT OF RECENT ECONOMIC DEVELOPMENTS ON PENSION COSTS

PSC DOCKET NO. 09-182
SECOND DATA REQUEST TO DELMARVA
FROM THE PSC STAFF
Revised Response

PSC 2-6. Referring to Delmarva's response to PSC 1-10, please provide an estimate of the 2009 pension expense that will be deferred if Delmarva's Petition is granted. Please provide separate estimates for the Delaware electric and gas divisions.

Revised Response:

Please refer to the table below.

(1) Line No.	(2) Item	(3) DE Electric Pension Expense	(4) DE Gas Pension Expense	(5) Total
1	2009 Pension Expense	$8,001,610	$3,927,053	$11,928,664
2				
3	Pension Income Currently in Rates	(970,783)	(177,042)	(1,147,825)
4				
5	Amount to be Deferred	8,972,393	4,104,095	13,076,489

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-44
For each of the past three rate case filings, provide: a) the amount of the increase requested, b) the percentage increase requested, c) the amount of increase granted, d)whether the case was litigated or settled, e) the total rate case costs incurred, and f) the effective date of new rates.

RESPONSE:

	Item	DPSC Docket No. 09-414 Electric Base Rate Case Filed September 18, 2009	DPSC Docket No. 06-284 Gas Base Rate Case Filed August 31, 2006	DPSC Docket No. 05-304 Electric Base Rate Case Filed September 1, 2005
(a)	Increase Requested ($000)	$26.195	$14.967	$1.569*
(b)	Percent Increase Requested	3.8%	6.62%	0.2%
(c)	Amount of Increase Granted ($000)	TBD	$9.000	$<11.103>
(d)	Litigated or Settled	Litigated	Settled	Litigated
(e)	Rate Case Costs Incurred **	$640,000	$290,000	$400,000
(f)	Effective Date of New Rates	4/19/10	4/1/07	5/1/06

* The filed increase was $5.063 million in electric rates, with a net increase of $1.569 million to distribution base rates after assigning $3.494 million in costs to the supply component of rates

** Represents best estimate of actual cost of case. Case costs not included in settlement or final decision. These costs represent incremental costs for the Commission's charges, Company consultants, lawyers, notice printing and transcripts costs.

Respondent: W. Michael VonSteuben

PSC DOCKET NO. 10-237
DE PSC STAFF'S FIRST SET OF ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-123
Provide copies of all union contracts in effect at the time of DPL's filing, and all that will be in effect during the rate effective period.

RESPONSE:
See the attached term sheets for the Local Union 1238 and 1307 contracts.

Respondent: Ernest L. Jenkins

PSC-LA-123

LU 1238 Final Key Terms

- 3-year Agreement – same as LBF (effective 2/1/10 to2/1/13)
- Wage Increase
    - No GWI in first year of contract (LBF originally had 2% retro if ratified by June 15th); GWI replaced by Lump Sum (see below)
    - 2% in second year of contract – (same as LBF)
    - 2% in third year of contract – (same as LBF)
- Lump Sum – One time non-base pay distribution of $800 (roughly equal to 2% x 7 months remaining in first year of contract)
- Pension Changes – see attached chart
- Job Security – no changes in Contract for existing employees; no job security protection for new employees (same as LBF)
- Medical (same as LBF)
    - No increase in employee contributions or co-pays
    - 3 Heritage plans with low enrollment will no longer be offered, effective 1-1-11
    - Existing employees may now select PHI Plans
- Dental/Vision (same as LBF)
    - No increase in employee contributions or co-pays
- Sick Pay (same as LBF)
    - Changes designed to reward good attendance and discourage abuse
- Meals
    - Meal allowance eligibility after 11 hours (was 10) – same as LBF
    - Increase in meal allowances (consistent with Pepco and ACE)
        - $13.00 effective 7/19/10
        - $14.00 effective 2/1/11
    - No meal allowance if Company furnishes meal
    - If work continues past 11 hours, eligible for additional hour to eat meal
- Departmental Agreements – (same as LBF)
    - Line – changes in duties and increases in pay.
    - Gas – changes in duties and increases in pay
    - Relay – changes in duties and increases in pay.
    - Facility Services – changes in qualifications and increases in pay for Electricians
    - VRM – changes in qualifications with financial incentives to acquire ASE Certifications

    - Customer Care – Company to increase number of Call Center reps in each year of Contract
- Increased safety allowances – (same as LBF)
    - Safety shoes
    - Safety Eyeglasses
    - Fire Retardant Clothing
- Increased Vacation (same as LBF)
    - Employees hired before July 1 each year get 3 days in year of hire after 60 calendar days of work
    - 3 weeks after 5 years of service (was 7 years)
- Future employees (hired after 9-1-10) – same as LBF
    - Improved vacation benefits in year of hire
    - Increased 401k match
    - No subsidized Retiree Medical
    - No Job Security provision
    - Go into PHI Medical Plans (if hired after 1-1-11)
    - New pension plan (less generous than for existing employees)
- Standby (same as LBF)
    - In addition to weekly standby, Company can implement daily standby.
    - Employees assigned daily standby will be paid three (3) hours of straight time pay.
    - Company will use daily standby only on holidays, holiday weekends or when there is a potential system emergency.
- Floating Lunch (same as LBF)
    - At management's discretion, field personnel may, for the needs of the service, work through the normal mid-day meal period and be given an alternate meal period within the hours of 11:00 A.M. and 1:00 P.M.

PSC-LA-123

LU 1307 Final Key Terms

- 3-year Agreement
- Wage Increase – same as Local 1238
    - No GWI in first year of contract
    - 2% in second year of contract
    - 2% in third year of contract
- Lump Sum – One time non-base pay distribution of $1200 (roughly equal to 2% x 12 months remaining in first year of contract) payable as soon as practical after Contract ratification
- Pension Changes – same as Local 1238
    - New plan for employees hired after 9-1-10
    - Revision of terms for existing employees (some grandfathering)
        - Elimination free Joint & Survivor benefit
        - Benefit no longer calculated on W-2 earnings (base pay only)
- Job Security – no changes in Contract for existing employees; no job security protection for new employees – same as Local 1238
- Medical – same as Local 1238
    - No increase in employee contributions or co-pays
    - 3 Heritage plans with low enrollment will no longer be offered, effective 1-1-11
    - Existing employees may now select PHI Plans
- Dental/Vision – same as Local 1238
    - No increase in employee contributions or co-pays
- Sick Pay – same as Local 1238
    - Changes designed to reward good attendance and discourage abuse
- Meals
    - Meal allowance eligibility after 11 hours (was 10)
    - Increase in meal allowances (consistent with Pepco and ACE)
        - $13.00 effective 3 payroll periods after ratification
        - $14.00 effective 6/26/11
    - No meal allowance if Company furnishes meal
    - Missed meal times established – same as Local 1238
- Departmental Agreements
    - Line – changes in duties and increases in pay – similar to Local 1238
    - Relay – changes in duties and increases in pay – similar to Local 1238
    - VRM – changes in qualifications with financial incentives to acquire ASE Certifications – same as Local 1238

- Customer Care
  - Elimination of several adverse business practices/side agreements;
  - Call Center will now work 24/7 (alternating with Carney's Point), effective in 2011;
  - Lengthened probationary period from 8 months to one year – same as Local 1238
- Increased safety allowances – same as Local 1238
  - Safety shoes
  - Safety Eyeglasses
  - Fire Retardant Clothing
- Remote Reporting
  - Can require employees in Electrical Maintenance to remote report on capital projects;
  - Employees paid reporting allowance based on distance
- Eliminated travel pay for employees with take-home vehicles
- Increased Vacation – same as Local 1238 and Local 1900
  - Employees hired before July 1 each year get 3 days in year of hire after 60 calendar days of work
  - 3 weeks after 5 years of service (was 7 years)
- Future employees (hired after 9-1-10) – same as Local 1238
  - Improved vacation benefits in year of hire
  - Increased 401k match
  - No subsidized Retiree Medical
  - No Job Security provision
  - Go into PHI Medical Plans (if hired after 1-1-11)
  - New pension plan (less generous than for existing employees)
- Floating Lunch – same as Local 1238
  - At management's discretion, field personnel may, for the needs of the service, work through the normal mid-day meal period and be given an alternate meal period within the hours of 11:00 A.M. and 1:00 P.M.

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-19
Please provide a description of all non-executive incentive compensation programs. For each program, please provide a) a description of the program, b) the amount included in the Company's claim, and c) the actual amount incurred in each of the past five years.

RESPONSE:

a) See the attached Annual incentive Plan (AIP) document (DPA-19 2010 AIP Document).
b) See Adjustments 5 & 6, update 12+0 of Company Witness VonSteuben's Supplemental Testimony.
c) For plan years 2005-2009 the actual amount incurred is as follows for all of PHI including Pepco, Atlantic City Electric and Delmarva Power:

Plan Year	Payout Year	Amt Incurred
2005	2006	$12,105,425.50
2006	2007	No payout
2007	2008	$13,876,841.12
2008	2009	$17,489,190.18
2009	2010	$9,335,052.04

Respondent: Jay C. Ziminsky

Pepco Holdings, Inc.

2010
Annual Incentive Plan

An Overview of the Annual Incentive Plan (AIP)

The purpose of the AIP is to monetarily recognize eligible management employees who achieve or exceed pre-established annual goals that are crucial to the improved performance of the employee's Team and PHI as a whole. Employees have an opportunity to earn awards for the performance and results they help to achieve.

Earning awards is intended to be challenging. PHI has established goals that must be met in order to enhance our competitiveness as a company within our industry. Specific, measurable goals provide a clear line of sight linking work results to important financial, customer and employee strategic objectives.

Many high-performing companies use incentive pay in combination with base pay to drive the performance and results essential to their success. As PHI strives to be competitive, we are including both base pay and incentive pay as part of our total market-based pay program.

Incentive pay does not become part of an employee's base pay; it must be earned every year by meeting stretch goals for that year. Teamwork will always be a key factor in earning awards.

Plan Year

The Plan Year is January 1 to December 31.

Eligibility

All PHI management employees who do not participate in any other incentive plan are eligible to participate in the AIP (excluding PES and CES employees). New hires must be employed and actively at work before October 1 of the plan year in order to be eligible for that year. Part Time management employees, in addition to being employed and actively at work before October 1 must also have a regular schedule of at least 20 hours per week in order to be a participant in the plan. Awards for new hires are prorated based on the amount of time an employee is employed during the year. For example, an employee hired on April 1 and who is still employed on December 31 would be eligible for an award based on nine months of employment.

Performance Measures

Performance will be measured at the Business Unit level only and is based on the 2010 Executive Incentive Plan. For Utility Operations employees, the Utility Operations' earnings must reach a 93% threshold to qualify for any potential payout. Potential payout for Corporate Services employees is based on an overall corporate earnings threshold of 90%. **Corporate Services employees are eligible to receive a payout only to the extent that Power Delivery and/or Non-Regulated earnings meet or exceed threshold levels and such awards shall not exceed 50% of target if PHI corporate earnings do not exceed threshold levels.** The plan is intended to support the PHI WAY and PHI's Blueprint for the Future and align employees with key business goals and executive area balanced scorecards.

Target Awards

A position's pay grade and salary determines the target award. Target awards will range from 5% to 15% percent of base pay. Target awards are higher for higher grades due to the greater scope and responsibility of positions at higher levels and their potential impact on results.

A target award is expressed as a percent of base salary. The target awards are market based.

Pay Grade	Target Award (% of base pay)
15 – 16	**15%**
13 – 14	**12%**
11 – 12	**10%**
8 – 10	**8%**
5 – 7	**6%**
1 – 4	**5%**

Rewarding Exceptional Results

The actual award potential will range from zero to a maximum of 150% of target award level depending on performance at the Business Unit level. Awards can exceed 100% of the targets only for truly exceptional results that are documented.

Award Calculation Using "Multipliers"

At year's end, the Company will assess performance results and assign scores that equate to Business Unit "multipliers" that can be as high as 150% of target award level. The multipliers are used to mathematically determine the actual award payment as follows:

Business Unit Performance Multiplier	**x**	**Individual AIP Award Percent**	**x**	**Employee's Base Salary**	**=**	**Annual Incentive Plan Payout**

Business Unit Goals

- Business Unit performance goals are weighted as follows:

  (1) 50% for the PHI Balanced Scorecard (based on the Utility Operations Balanced Scorecard)

  (2) 50% for the Executive Area Balanced Scorecard

Business Unit Goals (continued)

(3) 25% for the Group Balanced Scorecard (Optional)
(If used, the Executive Area weight reduces to 25%)

The formula for Corporate Services employees when PHI Corporate Earnings are met is: [50% (Utility BSC x 80% + Competitive BSCs x 20%) + 50% Executive Area BSC (Tier 2 = 25% + Tier 3 = 25% where applicable)] x Salary x AIP Percent
NOTE: To create better alignment with Power Delivery, Corporate Services employees' payout is capped at 50% when PD meets or exceeds its threshold target and PHI does not meet PHI's Corporate Earnings threshold.

Award Payment

- The target award will be calculated using the employee's base salary in effect on the last day of the plan year unless the employee receives a promotion or salary adjustment during the plan year. In those instances the award will be prorated. (See bullet 6).

- The target award for part-time employees will be calculated using the employee's base earnings during the part-time status.

- The award will be paid following the end of the plan year and generally is paid sometime in March. Awards are subject to federal, state and local taxes, as required by law.

- If an employee terminates employment after the plan year ends, but before the award payout is made, he/she will still receive the award.

- Each employee will receive an individual payout sheet that shows how his/her award was calculated and the associated Business Unit multipliers used in the calculation.

- In certain situations, awards will be prorated:

    - If an employee changes pay grades during the plan year and becomes eligible for a different target incentive award, the award will be prorated according to the number of days spent in each grade and the salary associated with the grade for that time period.

    - If an employee transfers from one Business Unit to another Business Unit during the year, the award he/she receives will be prorated according to the number of days spent in each Business Unit and the associated salary during the time spent in each Business Unit.

    - If an employee changes status from full-time to part-time or vice versa during the year, the award will be prorated according to the number of days spent in the part-time status and the number of days spent in the full-time status. The prorated award will use the base earnings during the part-time status for the part-time piece and the salary during the full-time status for the full-time piece of the calculation.

- When a bargaining unit employee is transferred to a management position or vice versa the award is prorated based on the employee's transfer date.

Award Payment (continued)

- If the employee is a management new hire who is eligible for the plan and was actively at work prior to October 1 of the plan year, the award is prorated based on the number of days employed by the Company.

- In cases of death, long-term disability or retirement, awards are prorated based on the number of days that the Incentive Plan participant was an active employee during the plan year.

- If the employee is absent from work for 20 or more consecutive days in a paid or unpaid status (with the exception of vacation and floating holidays), the award is prorated based on the number of days actively at work during the plan year. The paid or unpaid leave status includes illness, FMLA, military leave, workers' compensation, approved and unapproved absences, suspensions and jury duty.

- No award payment will be made in any of the following situations:

  - When the employee's overall individual annual performance rating is a 1 (Unsatisfactory) in the Performance Accountability System (PAS). In addition, a rating of 2 (Performance Improvement Needed) for two consecutive years is not eligible for an award (starting with the 2005 performance year).

  - When the employee terminates employment (for reasons other than death, disability or retirement) before the end of the plan year. In addition, a prorated award will not be paid if an employee retires from a severance leave of absence.

Reporting Results

- Business Unit Goals

  Business Unit leaders will report results to People Strategy & HR and to eligible employees quarterly.

  - Business Unit leaders should publish a report for their management employees discussing Business Unit goal results.

  - Business Unit leaders should report on:
    - ♦ Progress or problems regarding each Business Unit goal
    - ♦ Each Business Unit goal's performance result and multiplier
    - ♦ The composite Business Unit multiplier based on each goal's weighting factor

Continuation of the Plan

The Company may continue, terminate or adjust the Plan at any time.

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-98
Please provide the Lake Consulting study regarding increases in medical costs, referenced on page 7, lines 1-5 of Mr. Jenkins testimony.

RESPONSE:
See the attachments which includes Lake Consulting studies attached (DPA-98 Lake Consulting.doc, DPA-98 Lake Consulting Att 2.doc, DPA-98 Lake Consulting Att 3.doc).

Respondent: Ernest L. Jenkins

Lake Consulting, Inc.
7200 Bradley Boulevard
Bethesda, MD 20817
301-365-1964

May 17, 2010

Eileen M. Kennedy
Accounting Program Manager
PEPCO Holdings, Inc.
PO Box 9239
Newark, DE 19714

Dear Eileen:

Here are the results of our medical trend survey for the second quarter of 2010. This represents the projected trends in use for the second quarter of 2010. Six companies in the region participated, and we thank all of them. We present the company by company results, the mean, the median, and the range of rates in each category of plan.

- For this quarter, three of the seven categories showed changes from the mean average projected first quarter 2010 trends. HMO showed an increase of 0.1%, Dental showed an increase of .2%, and Pharmacy showed a decrease of 0.2%. POS, PPO, Indemnity and CDHP showed no change.
- When compared to last quarter, three companies showed no changes in projected trends, and the other three companies had at least one change. One company increased Dental by 1.0%, and another company decreased Pharmacy by 1.0%. One company increased HMO by 0.5%, increased POS by 0.1%, and increased both PPO and CDHP by 0.2%.
- The HMO second quarter 2010 mean average trend shows an increase of 0.1% over the trend for first quarter 2010 as the result of one company increasing their HMO trend by 0.5%.
- The POS second quarter 2010 mean average trend shows no change from this trend for first quarter 2010. One company did increase their POS trend 0.1%, but this is not enough to show an impact on the average.
- The PPO second quarter 2010 mean average trend shows no change from this trend for first quarter 2010. One company increased their POS trend 0.2%, which again is not enough to show an impact.
- The Indemnity second quarter 2010 mean average trend shows no change from this trend for first quarter 2010 because all five companies reporting this trend made no change to it.
- The Dental second quarter 2010 mean average trend shows an increase of 0.2% over the mean average projected Dental trends for first quarter 2010. This is the result of one company increasing this trend by 1.0%.

- The Pharmacy second quarter 2010 mean average trend decreased 0.2% with one company decreasing their Pharmacy trend by 1.0%.
- The Consumer Driven Health Plan second quarter 2010 mean average trend showed no change from than that of first quarter 2010. One company increased this trend 0.2%, but this is not enough to show an impact on the average. Please note that we have started including a CDHP summary of quarterly trends beginning with first quarter 2007.
- In the second quarter 2010 trend survey, we had two reports of CDHP Pharmacy trends different from trends for CDHP base plans. In each case, the CDHP Pharmacy trend is 1.0% larger.

This quarter, the mean average projected HMO and POS trends are the lowest medical trends; both are at 11.1%, with HMO rates ranging from 5.5% to 13.4% and POS rates ranging from 6.5% to 13.4%. Current CDHP trends were the next lowest, 11.4%, with rates ranging from 7.2% to 13.4%. PPO trends are slightly more at 12.2%, with rates ranging from 9.2% to 14.4%. Current Indemnity trends are still the highest of the medical trends at 14.6%, with a range of 13.4% to 16.5%. Dental trends are lower than medical, 7.0% mean average, with a range from 5.5% to 8.5%. Pharmacy trends, at 11.6% mean average, range from 6.0% to 14.6%.

We also want to show you these trends over time, so we have summarized by type of medical plan the trends since we began this survey. You will be able to see at a glance how your plan has compared with other plans. During the forty-six quarters we have collected data for all but CDHP (of which sixteen are displayed), we see the following increases:

- The mean average of HMO trends has increased from 5.3% to 11.1%.
- The mean average of POS trends has increased from 6.6% to 11.1%.
- The mean average of PPO trends has increased from 9.3% to 12.2%.
- The mean average of Indemnity trend has remained at its highest (14.6%) since first quarter 2006.
- The mean average of Pharmacy trends has decreased from 13.9% to 11.6 %. While there were substantial trend increases during the early years of our survey, the Pharmacy trend has come back below our original survey trend levels with many quarterly decreases since then.

For the fourteen quarters we have reported CDHP, the mean average trends has increased from 10.5% to 11.4%

We hope you will find these results both interesting and of value. We will send another survey soon, asking for third quarter 2010 trends. Again, we thank you for your interest.

Sincerely,

Gary D. Lake, FSA　　Jon R. Jennings

Gary D. Lake, FSA
Consulting Actuary

Jon R. Jennings
Consultant

Enclosures

Participating Companies

Aetna/USHealthCare

CareFirst of Maryland

CareFirst of Washington, DC

CIGNA HealthCare, Mid Atlantic

Kaiser Foundation of the Mid-Atlantic States

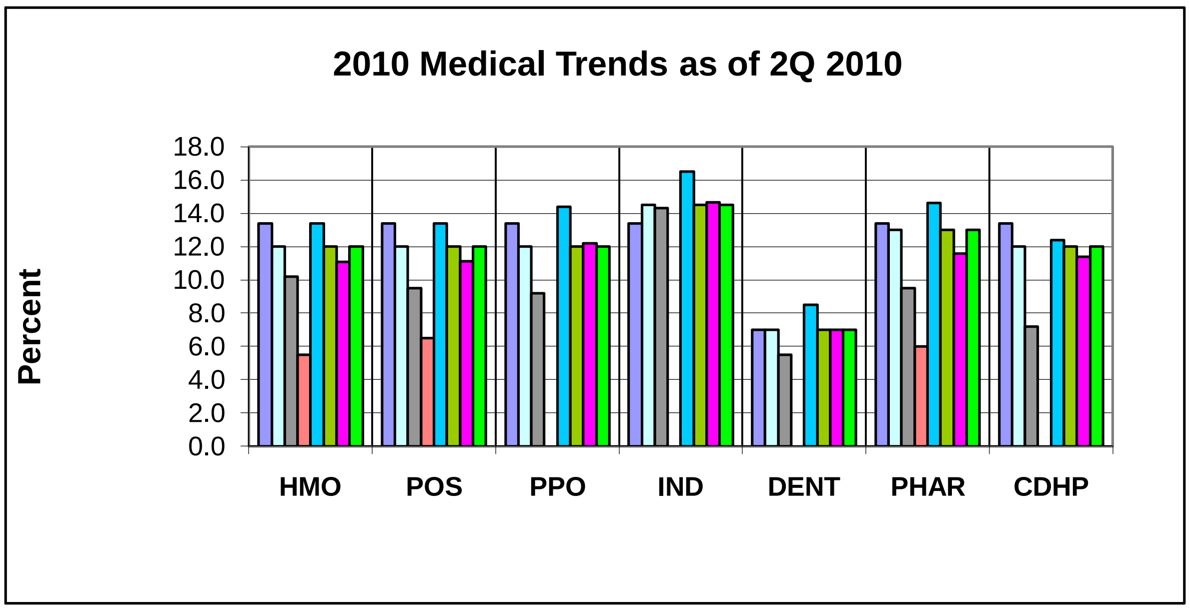
UnitedHealth Group

LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY
VA, MD, DC Area

DPA-98

Annual Medical Trends Being Used for 2nd Quarter, 2010

	Company C	Company D	Company E	Company F	Company G	Company I	Mean Ave	Median	Range of Rates Low	Range of Rates High
HMO	13.4	12.0	10.2	5.5	13.4	12.0	11.1	12.0	5.5	13.4
POS	13.4	12.0	9.5	6.5	13.4	12.0	11.1	12.0	6.5	13.4
PPO	13.4	12.0	9.2		14.4	12.0	12.2	12.0	9.2	14.4
Indemnity	13.4	14.5	14.3		16.5	14.5	14.6	14.5	13.4	16.5
Dental	7.0	7.0	5.5		8.5	7.0	7.0	7.0	5.5	8.5
Pharmacy	13.4	13.0	9.5	6.0	14.6	13.0	11.6	13.0	6.0	14.6
CDHP	13.4	12.0	7.2		12.4	12.0	11.4	12.0	7.2	13.4



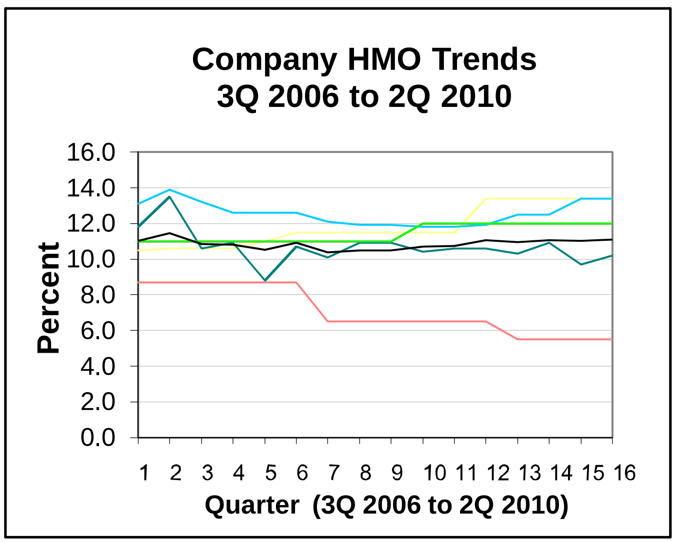
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

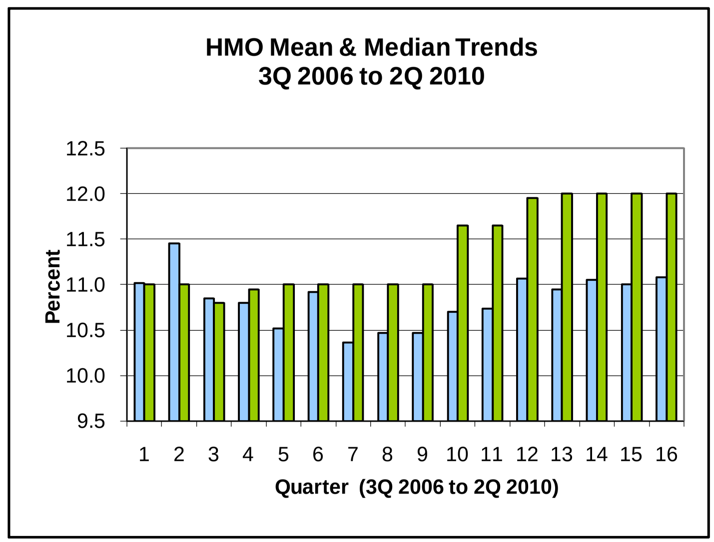
DPA-98

VA, MD, DC Area

HMO Summary for 3Q 2006 to 2Q 2010

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2006	10.5	11.0	11.8	8.7	13.1	11.0	11.0	11.0	8.7	13.1
4 Q 2006	10.6	11.0	13.5	8.7	13.9	11.0	11.5	11.0	8.7	13.9
1 Q 2007	10.6	11.0	10.6	8.7	13.2	11.0	10.9	10.8	8.7	13.2
2 Q 2007	10.6	11.0	10.9	8.7	12.6	11.0	10.8	11.0	8.7	12.6
3 Q 2007	11.0	11.0	8.8	8.7	12.6	11.0	10.5	11.0	8.7	12.6
4 Q 2007	11.5	11.0	10.7	8.7	12.6	11.0	10.9	11.0	8.7	12.6
1 Q 2008	11.5	11.0	10.1	6.5	12.1	11.0	10.4	11.0	6.5	12.1
2 Q 2008	11.5	11.0	10.9	6.5	11.9	11.0	10.5	11.0	6.5	11.9
3 Q 2008	11.5	11.0	10.9	6.5	11.9	11.0	10.5	11.0	6.5	11.9
4 Q 2008	11.5	12.0	10.4	6.5	11.8	12.0	10.7	11.7	6.5	12.0
1 Q 2009	11.5	12.0	10.6	6.5	11.8	12.0	10.7	11.7	6.5	12.0
2 Q 2009	13.4	12.0	10.6	6.5	11.9	12.0	11.1	12.0	6.5	13.4
3 Q 2009	13.4	12.0	10.3	5.5	12.5	12.0	11.0	12.0	5.5	13.4
4 Q 2009	13.4	12.0	10.9	5.5	12.5	12.0	11.1	12.0	5.5	13.4
1 Q 2010	13.4	12.0	9.7	5.5	13.4	12.0	11.0	12.0	5.5	13.4
2 Q 2010	13.4	12.0	10.2	5.5	13.4	12.0	11.1	12.0	5.5	13.4



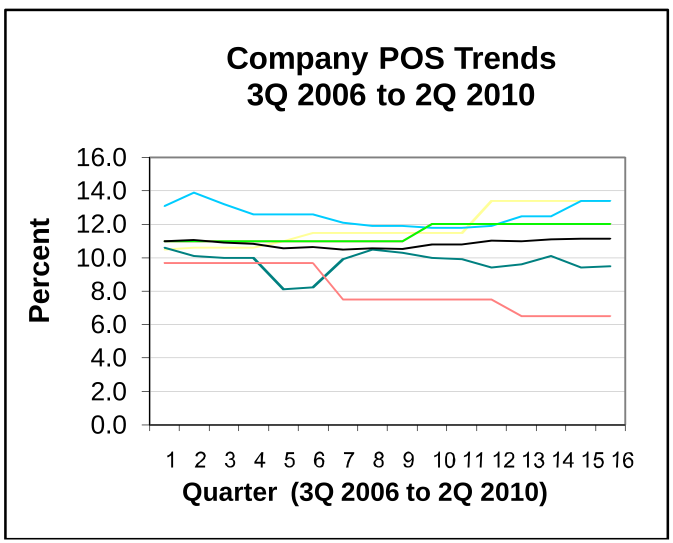


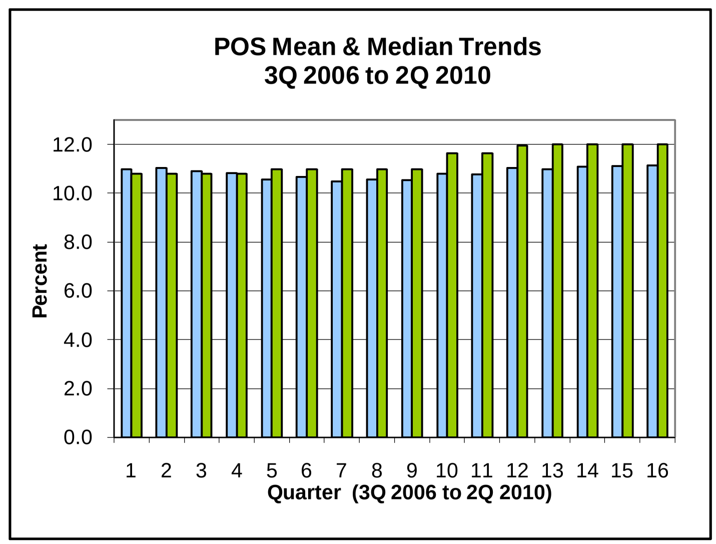
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

POS Summary for 3Q 2006 to 2Q 2010

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2006	10.5	11.0	10.6	9.7	13.1	11.0	11.0	10.8	9.7	13.1
4 Q 2006	10.6	11.0	10.1	9.7	13.9	11.0	11.1	10.8	9.7	13.9
1 Q 2007	10.6	11.0	10.0	9.7	13.2	11.0	10.9	10.8	9.7	13.2
2 Q 2007	10.6	11.0	10.0	9.7	12.6	11.0	10.8	10.8	9.7	12.6
3 Q 2007	11.0	11.0	8.1	9.7	12.6	11.0	10.6	11.0	8.1	12.6
4 Q 2007	11.5	11.0	8.2	9.7	12.6	11.0	10.7	11.0	8.2	12.6
1 Q 2008	11.5	11.0	9.9	7.5	12.1	11.0	10.5	11.0	7.5	12.1
2 Q 2008	11.5	11.0	10.5	7.5	11.9	11.0	10.6	11.0	7.5	11.9
3 Q 2008	11.5	11.0	10.3	7.5	11.9	11.0	10.5	11.0	7.5	11.9
4 Q 2008	11.5	12.0	10.0	7.5	11.8	12.0	10.8	11.7	7.5	12.0
1 Q 2009	11.5	12.0	9.9	7.5	11.8	12.0	10.8	11.7	7.5	12.0
2 Q 2009	13.4	12.0	9.4	7.5	11.9	12.0	11.0	12.0	7.5	13.4
3 Q 2009	13.4	12.0	9.6	6.5	12.5	12.0	11.0	12.0	6.5	13.4
4 Q 2009	13.4	12.0	10.1	6.5	12.5	12.0	11.1	12.0	6.5	13.4
1 Q 2010	13.4	12.0	9.4	6.5	13.4	12.0	11.1	12.0	6.5	13.4
2 Q 2010	13.4	12.0	9.5	6.5	13.4	12.0	11.1	12.0	6.5	13.4



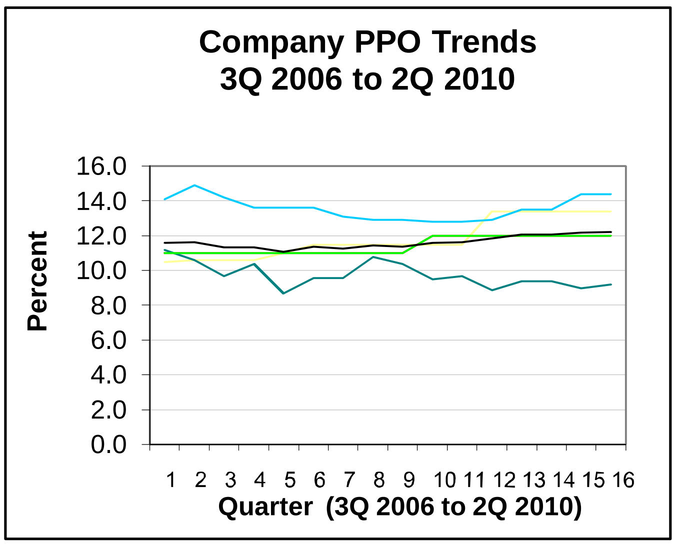


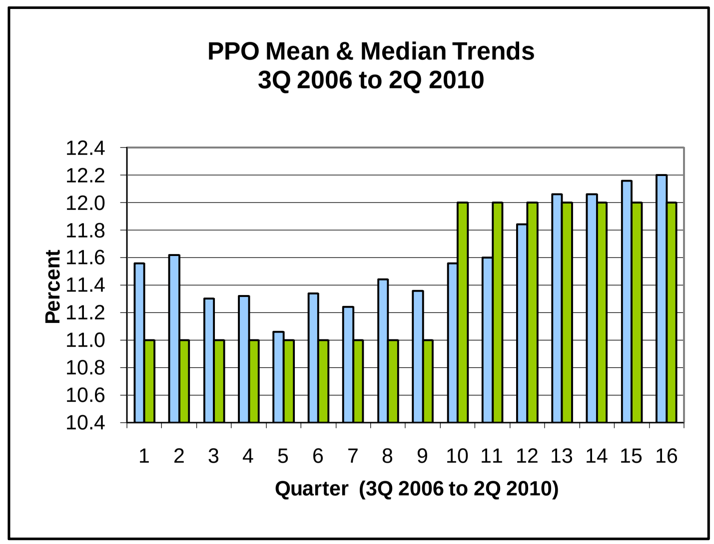
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

PPO Summary for 3Q 2006 to 2Q 2010

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2006	10.5	11.0	11.2		14.1	11.0	11.6	11.0	10.5	14.1
4 Q 2006	10.6	11.0	10.6		14.9	11.0	11.6	11.0	10.6	14.9
1 Q 2007	10.6	11.0	9.7		14.2	11.0	11.3	11.0	9.7	14.2
2 Q 2007	10.6	11.0	10.4		13.6	11.0	11.3	11.0	10.4	13.6
3 Q 2007	11.0	11.0	8.7		13.6	11.0	11.1	11.0	8.7	13.6
4 Q 2007	11.5	11.0	9.6		13.6	11.0	11.3	11.0	9.6	13.6
1 Q 2008	11.5	11.0	9.6		13.1	11.0	11.2	11.0	9.6	13.1
2 Q 2008	11.5	11.0	10.8		12.9	11.0	11.4	11.0	10.8	12.9
3 Q 2008	11.5	11.0	10.4		12.9	11.0	11.4	11.0	10.4	12.9
4 Q 2008	11.5	12.0	9.5		12.8	12.0	11.6	12.0	9.5	12.8
1 Q 2009	11.5	12.0	9.7		12.8	12.0	11.6	12.0	9.7	12.8
2 Q 2009	13.4	12.0	8.9		12.9	12.0	11.8	12.0	8.9	13.4
3 Q 2009	13.4	12.0	9.4		13.5	12.0	12.1	12.0	9.4	13.5
4 Q 2009	13.4	12.0	9.4		13.5	12.0	12.1	12.0	9.4	13.5
1 Q 2010	13.4	12.0	9.0		14.4	12.0	12.2	12.0	9.0	14.4
2 Q 2010	13.4	12.0	9.2		14.4	12.0	12.2	12.0	9.2	14.4





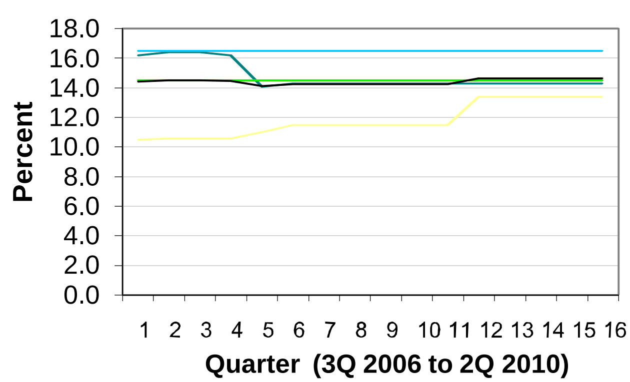
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

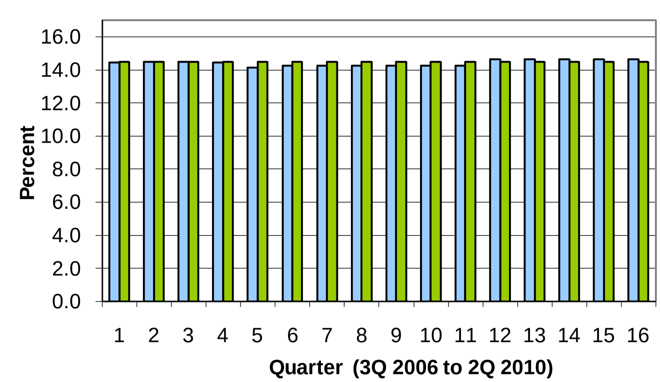
Indemnity Summary for 3Q 2006 to 2Q 2010

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2006	10.5	14.5	16.2		16.5	14.5	14.4	14.5	10.5	16.5
4 Q 2006	10.6	14.5	16.4		16.5	14.5	14.5	14.5	10.6	16.5
1 Q 2007	10.6	14.5	16.4		16.5	14.5	14.5	14.5	10.6	16.5
2 Q 2007	10.6	14.5	16.2		16.5	14.5	14.5	14.5	10.6	16.5
3 Q 2007	11.0	14.5	14.1		16.5	14.5	14.1	14.5	11.0	16.5
4 Q 2007	11.5	14.5	14.3		16.5	14.5	14.3	14.5	11.5	16.5
1 Q 2008	11.5	14.5	14.3		16.5	14.5	14.3	14.5	11.5	16.5
2 Q 2008	11.5	14.5	14.3		16.5	14.5	14.3	14.5	11.5	16.5
3 Q 2008	11.5	14.5	14.3		16.5	14.5	14.3	14.5	11.5	16.5
4 Q 2008	11.5	14.5	14.3		16.5	14.5	14.3	14.5	11.5	16.5
1 Q 2009	11.5	14.5	14.3		16.5	14.5	14.3	14.5	11.5	16.5
2 Q 2009	13.4	14.5	14.3		16.5	14.5	14.6	14.5	13.4	16.5
3 Q 2009	13.4	14.5	14.3		16.5	14.5	14.6	14.5	13.4	16.5
4 Q 2009	13.4	14.5	14.3		16.5	14.5	14.6	14.5	13.4	16.5
1 Q 2010	13.4	14.5	14.3		16.5	14.5	14.6	14.5	13.4	16.5
2 Q 2010	13.4	14.5	14.3		16.5	14.5	14.6	14.5	13.4	16.5

Company Indemnity Trends
3Q 2006 to 2Q 2010



Indemnity Mean & Median Trends
3Q 2006 to 2Q 2010

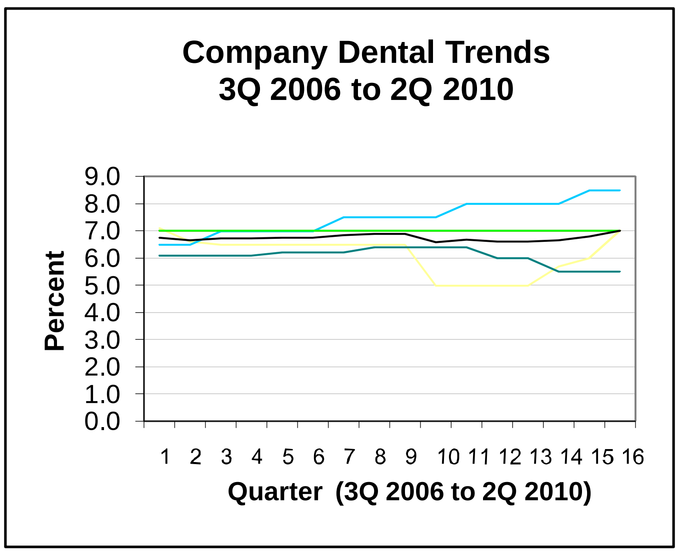


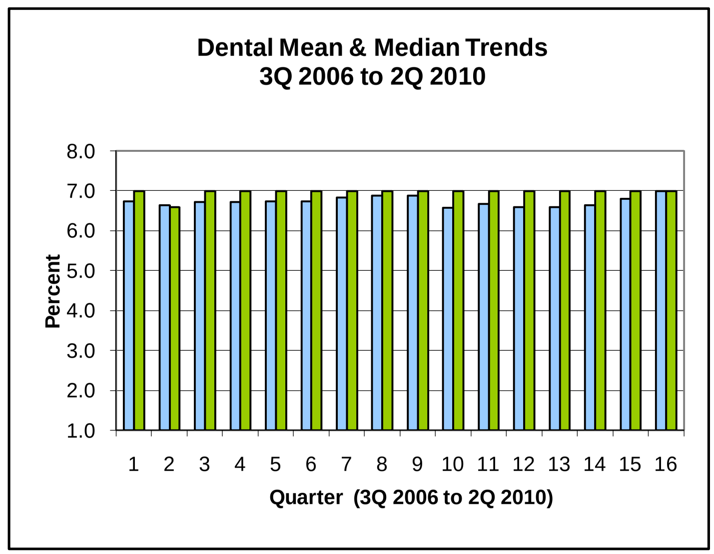
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Dental Summary for 3Q 2006 to 2Q 2010

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2006	7.1	7.0	6.1		6.5	7.0	6.7	7.0	6.1	7.1
4 Q 2006	6.6	7.0	6.1		6.5	7.0	6.6	6.6	6.1	7.0
1 Q 2007	6.5	7.0	6.1		7.0	7.0	6.7	7.0	6.1	7.0
2 Q 2007	6.5	7.0	6.1		7.0	7.0	6.7	7.0	6.1	7.0
3 Q 2007	6.5	7.0	6.2		7.0	7.0	6.7	7.0	6.2	7.0
4 Q 2007	6.5	7.0	6.2		7.0	7.0	6.7	7.0	6.2	7.0
1 Q 2008	6.5	7.0	6.2		7.5	7.0	6.8	7.0	6.2	7.5
2 Q 2008	6.5	7.0	6.4		7.5	7.0	6.9	7.0	6.4	7.5
3 Q 2008	6.5	7.0	6.4		7.5	7.0	6.9	7.0	6.4	7.5
4 Q 2008	5.0	7.0	6.4		7.5	7.0	6.6	7.0	5.0	7.5
1 Q 2009	5.0	7.0	6.4		8.0	7.0	6.7	7.0	5.0	8.0
2 Q 2009	5.0	7.0	6.0		8.0	7.0	6.6	7.0	5.0	8.0
3 Q 2009	5.0	7.0	6.0		8.0	7.0	6.6	7.0	5.0	8.0
4 Q 2009	5.7	7.0	5.5		8.0	7.0	6.6	7.0	5.5	8.0
1 Q 2010	6.0	7.0	5.5		8.5	7.0	6.8	7.0	5.5	8.5
2 Q 2010	7.0	7.0	5.5		8.5	7.0	7.0	7.0	5.5	8.5



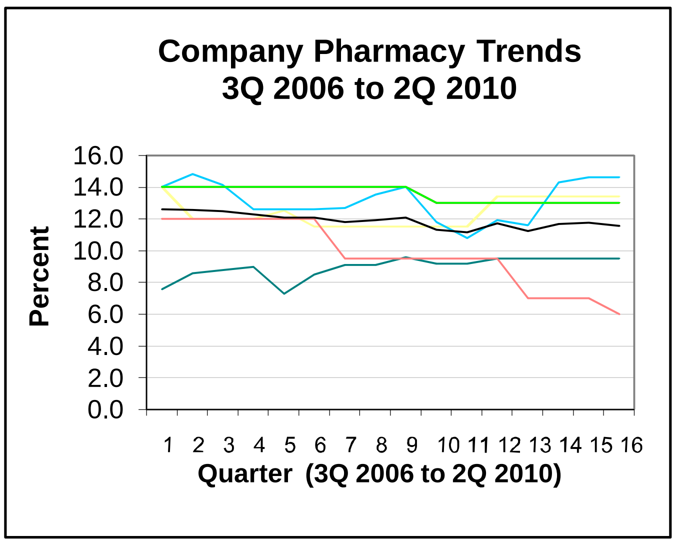


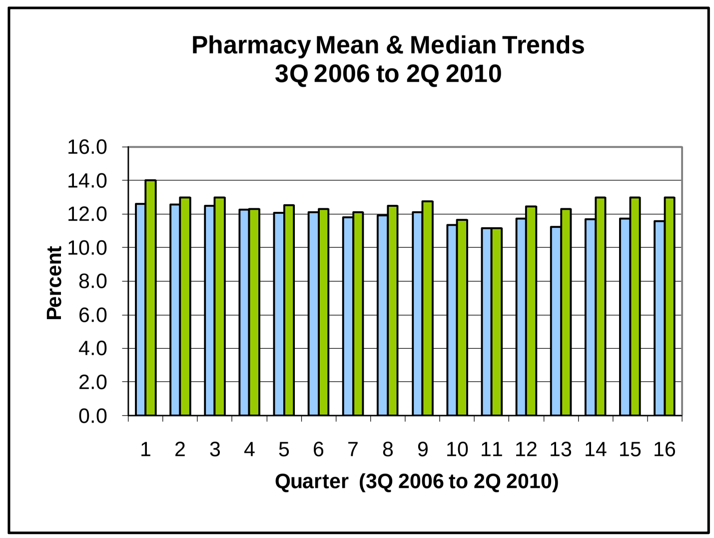
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

Pharmacy Summary for 3Q 2006 to 2Q 2010

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
3 Q 2006	14.0	14.0	7.6	12.0	14.0	14.0	12.6	14.0	7.6	14.0
4 Q 2006	12.0	14.0	8.6	12.0	14.8	14.0	12.6	13.0	8.6	14.8
1 Q 2007	12.0	14.0	8.8	12.0	14.1	14.0	12.5	13.0	8.8	14.1
2 Q 2007	12.0	14.0	9.0	12.0	12.6	14.0	12.3	12.3	9.0	14.0
3 Q 2007	12.5	14.0	7.3	12.0	12.6	14.0	12.1	12.6	7.3	14.0
4 Q 2007	11.5	14.0	8.5	12.0	12.6	14.0	12.1	12.3	8.5	14.0
1 Q 2008	11.5	14.0	9.1	9.5	12.7	14.0	11.8	12.1	9.1	14.0
2 Q 2008	11.5	14.0	9.1	9.5	13.5	14.0	11.9	12.5	9.1	14.0
3 Q 2008	11.5	14.0	9.6	9.5	14.0	14.0	12.1	12.8	9.5	14.0
4 Q 2008	11.5	13.0	9.2	9.5	11.8	13.0	11.3	11.7	9.2	13.0
1 Q 2009	11.5	13.0	9.2	9.5	10.8	13.0	11.2	11.2	9.2	13.0
2 Q 2009	13.4	13.0	9.5	9.5	11.9	13.0	11.7	12.5	9.5	13.4
3 Q 2009	13.4	13.0	9.5	7.0	11.6	13.0	11.3	12.3	7.0	13.4
4 Q 2009	13.4	13.0	9.5	7.0	14.3	13.0	11.7	13.0	7.0	14.3
1 Q 2010	13.4	13.0	9.5	7.0	14.6	13.0	11.8	13.0	7.0	14.6
2 Q 2010	13.4	13.0	9.5	6.0	14.6	13.0	11.6	13.0	6.0	14.6



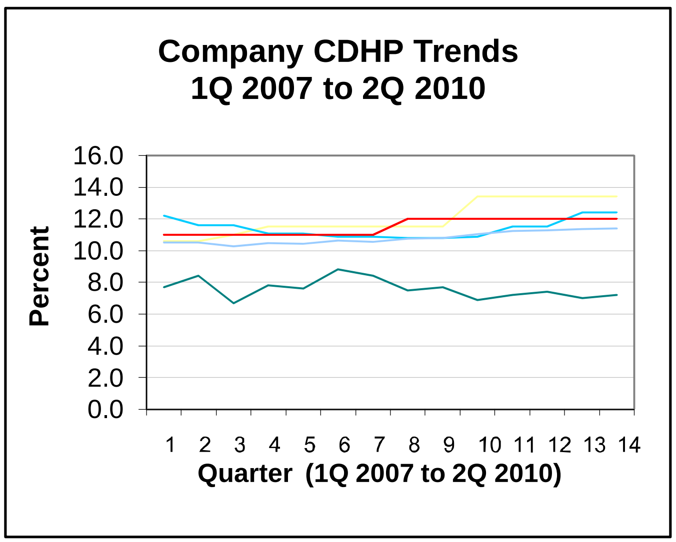


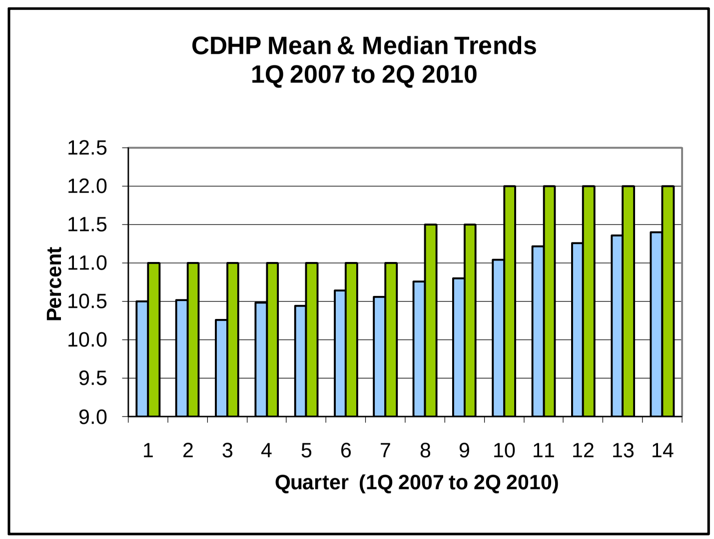
LAKE CONSULTING, INC.
QUARTERLY MEDICAL TREND SURVEY

VA, MD, DC Area

CDHP Summary for 1Q 2007 to 2Q 2010

	Co. C	Co. D	Co. E	Co. F	Co. G	Co. I	Mean Ave	Median	Range of Rates Low	Range of Rates High
1 Q 2007	10.6	11.0	7.7		12.2	11.0	10.5	11.0	7.7	12.2
2 Q 2007	10.6	11.0	8.4		11.6	11.0	10.5	11.0	8.4	11.6
3 Q 2007	11.0	11.0	6.7		11.6	11.0	10.3	11.0	6.7	11.6
4 Q 2007	11.5	11.0	7.8		11.1	11.0	10.5	11.0	7.8	11.5
1 Q 2008	11.5	11.0	7.6		11.1	11.0	10.4	11.0	7.6	11.5
2 Q 2008	11.5	11.0	8.8		10.9	11.0	10.6	11.0	8.8	11.5
3 Q 2008	11.5	11.0	8.4		10.9	11.0	10.6	11.0	8.4	11.5
4 Q 2008	11.5	12.0	7.5		10.8	12.0	10.8	11.5	7.5	12.0
1 Q 2009	11.5	12.0	7.7		10.8	12.0	10.8	11.5	7.7	12.0
2 Q 2009	13.4	12.0	6.9		10.9	12.0	11.0	12.0	6.9	13.4
3 Q 2009	13.4	12.0	7.2		11.5	12.0	11.2	12.0	7.2	13.4
4 Q 2009	13.4	12.0	7.4		11.5	12.0	11.3	12.0	7.4	13.4
1 Q 2010	13.4	12.0	7.0		12.4	12.0	11.4	12.0	7.0	13.4
2 Q 2010	13.4	12.0	7.2		12.4	12.0	11.4	12.0	7.2	13.4





PSC DOCKET NO. 10-237
DE PSC STAFF'S FIRST SET OF ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-146
Explain fully and in detail any changes to officers' and/or employees' benefits (1) over each of the last five years and (2) projected to occur during the rate effective period.

RESPONSE:

The Company redesigned the benefit plans offered to management employees in 2005. This included the implementation of a PPO and HMO with increased deductibles and co-pays, prescription coinsurance, retiree medical cost caps and the elimination of subsidized retiree medical for new hires after January 1, 2005. In addition, PHI has increased employee medical contributions for management employees. Management employees hired on or after January 1, 2005 will accrue their retirement benefit under the PHI Sub-Plan.

The LU 1238 contract dated February 2005 stipulated various changes to employee benefit programs over the five contract years such as increased prescription co-pays and employee monthly contributions, as well as mandatory mail order.

Plan changes for 2010 include health plan vendor consolidation and the elimination of the Company's fully insured HMO plans for executives, management and union employees. In addition, all management employees, including executives, have increased medical plan co-pays and mandatory mail order for prescription drug coverage.

Additional plan changes for management employees include increased cost share for monthly contributions effective January 1, 2011. The Company will also increase deductibles for the PHI PPO in 2011. Co-pays are scheduled to increase in the PHI PPO and PHI HMO effective January 1, 2012.

In December 2009, the PHI Retirement Plan was amended to replace the current interest rates used to calculate lump sum payments with the PPA 3-segmented corporate bond rate. The Plan will phase in the corporate bond rate over a five year period beginning January 1, 2011 at 10%, January 1, 2012 at 20%; January 1, 2013 at 40%; January 1, 2014 at 70% and January 1, 2015 at 100%.

The Company and Local 1238 ratified a new collective bargaining agreement during 2010. As a result of this agreement, new employees of Local 1238 hired on or after September 1, 2010 will accrue their pension benefit under the PHI Sub-Plan rather than the Delmarva Sub-Plan and no longer be eligible for subsidized retiree medical. As a result of the change to their defined benefit plan, these employees will be eligible for the Company match of $.50 on each $1 contributed up to 6% base pay in the 401K plan. In addition, the terms of the Delmarva Sub-Plan were amended to revise the definition of pensionable earnings to base pay only and to eliminate the unreduced joint and survivor benefit. These changes will be applied to employees based on the number of years of service as of 9/1/2010. The plan was further revised to include a 36 month pop-up feature. The option of a lump sum payment was also eliminated for term-vested Local 1238 employees in the Delmarva Sub-Plan as of September 1, 2010.

PSC DOCKET NO. 10-237
DE PSC STAFF'S FIRST SET OF ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

The Company also made changes to the medical plans offered to Local 1238, including the elimination of the Standard Indemnity for all members and the requirement for new hires to participate in the PHI HMO or PHI PPO, with the same scheduled plan design changes as described above for management employees.

Respondent: Ernest L. Jenkins

PSC DOCKET NO. 10-237
DE PSC STAFF'S FIRST SET OF ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-145
Re: Jenkins direct, p. 7, lines 1-11: a. Provide a complete copy of the Lake Consulting, Inc. study. b. Provide detailed calculations showing how the proposed percentage increases of 8% and 5% for medical and dental & vision expense, respectively, were derived. c. Identify the amount that DPL's employees contribute to their health care costs and show how this amount was derived. Show detailed calculations, if applicable.

RESPONSE:

a) See response to DPA-98.
b) Medical trend increases as a result of health care inflation and utilization. The Company engages Gary Lake, Consulting Actuary, to assist in the development of the benefits trend for PHI. The Company trends are generally based on a regional survey conducted by Gary Lake as several of the Company's medical plan vendors participate in this survey.
c) Member of Local 1238 contribute 20% of the cost of medical and mental health/substance abuse benefits as negotiated in their union agreement. Management employees currently contribute 17.5% and 18% toward the PHI PPO and PHI HMO plans (including prescription), respectively. These amounts are determined annually by the Company's executive leadership based on a recommendation from the Benefits Team. Refer to the attached monthly 2010 rate chart below.

2010 EMPLOYEE MEDICAL CONTRIBUTIONS SUMMARY

Management	Total Cost	EE	Total Cost	EE+1	Total Cost	EE+FAM	EE Cost Share
PHI PPO	$ 365.61	$ 64	$ 731.20	$ 128	$ 1,096.81	$ 192	17.5%
PHI HMO	$ 321.24	$ 59	$ 642.46	$ 118	$ 963.70	$ 176	18.4%

Local 1238	Total Cost	EE	Total Cost	EE+1	Total Cost	EE+FAM	EE Cost Share
CIGNA PPO	$ 261.32	$ 52	$ 522.65	$ 105	$ 783.96	$ 157	20%
Aetna QPOS	$ 279.08	$ 56	$ 558.17	$ 112	$ 837.25	$ 167	20%
CareFirst PPO	$ 315.59	$ 63	$ 631.19	$ 126	$ 946.78	$ 189	20%
CareFirst EPO	$ 420.98	$ 84	$ 838.73	$ 168	$ 1,313.79	$ 263	20%
Standard Indemnity	$ 503.62	$ 101	$ 1,007.24	$ 201	$ 1,510.85	$ 302	20%

Respondent: Ernest L. Jenkins

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-34
Identify the amount that employees contribute to their health care costs and state how that amount is determined.

RESPONSE:

Members of Local 1238 and Local 1307 contribute 20% of the cost of medical and mental health/substance abuse benefits as negotiated in their union agreement. Management employees currently contribute 17.5% and 18.3 % toward the PHI PPO and PHI HMO plans (including prescription), respectively. These amounts are determined annually by the Company's executive leadership based on a recommendation from the Benefits Team.

Respondent: Ernest L. Jenkins

PSC DOCKET NO. 10-237
DE PSC STAFF'S FOLLOW UP ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-245
Refer to the response to DPA-34. Show in detail how the employee contribution rates towards the cost of medical etc. insurance has been reflected in the calculation of pro forma employee benefits expense.

RESPONSE:
Any impact from Company cost for a single employee cost of employee contribution rates towards the cost of medical and other benefits has been factored in the Company's pro-forma adjustments.

Respondent: Ernest L. Jenkins

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-33
Provide the most recent unit rates for the Company's medical and dental benefit plans and identify the number of employees for which each such rate is applicable.

RESPONSE:

As of September 2010	EMPLOYEE		EMPLOYEE&1		FAMILY	
MEDICAL PLANS	**Monthly Cost**	**Count**	**Monthly Cost**	**Count**	**Monthly Cost**	**Count**
PHI PPO	365.61	428	731.20	286	1096.81	307
PHI PPO $15	377.17	4	755.87	6	1133.82	4
PHI HMO	321.24	635	642.46	554	963.70	831
CIGNA PPO	351.73	68	705.01	50	1057.51	74
Aetna QPOS	369.49	32	740.53	47	1110.80	89
Carefirst BCBS Basic Indemnity	120.66	5	242.85	4	364.29	0
Carefirst BCBS Standard Indemnity	371.38	55	744.28	49	1116.44	46
Carefirst BCBS PPO	406.00	197	813.55	258	1220.33	386
Carefirst BCBS EPO	511.39	3	1021.09	5	1587.34	4

	EMPLOYEE				EMPLOYEE	
	Monthly Cost	**Count**			**Monthly Cost**	**Count**
DENTAL PLAN	36.29	1347	N/A	N/A	89.63	3185

Respondent: Ernest L. Jenkins

PSC DOCKET NO. 10-237
DE PSC STAFF'S FOLLOW UP ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-244
Refer to the response to DPA-33. Reconcile the rates listed in the response to the rates used in the Company's adjustment. Identify, quantify and explain fully each reconciling item.

RESPONSE:

The attached illustrates the Company's cost for a single employee only coverage for 2010 in comparison to 2009. The Lake Consulting Survey used for the Employee Benefits pro-forma adjustment includes an annual trend of 8% medical increases based on the responses from regional insurance carriers. Their responses are based on experience of their entire book of business by product type (i.e. PPO, HMO, etc.). The costs for the plans shown in the attachment are based on actual claims experience of the plan and average enrollment during the cost rate-setting period although the medical plan (i.e. PHI HMO) with the largest enrollment had a 7% increase in employee only costs. While the Company utilizes the Lake Consulting survey for its employee benefits forecast, there is greater variability in each plan's performance due to smaller risk pools and actual experience as shown in the attachment.

Respondent: Ernest L. Jenkins

Delmarva Power & Light Company **PSC-LA-244**
Delaware Gas - Docket No. 10-327
Employee Benefit Cost Rates - 2009 & 2010

	Employee Only Cost			
Item	2010	2009	Variance	2010 Enrollment
PHI PPO	$ 365.61	$ 370.67	-1%	1,021
PHI HMO	$ 321.24	$ 301.00	7%	2,020
CIGNA PPO	$ 351.73	$ 346.50	2%	192
Aetna QPOS	$ 369.49	$ 512.17	-28%	168
Basic Indemnity	$ 120.66	$ 137.83	-12%	9
Standard Imdemnity	$ 371.38	$ 474.42	-22%	150
Carefirst PPO	$ 406.00	$ 401.22	1%	841
Carefirst EPO	$ 511.39	$ 473.99	8%	12
Dental	$ 36.29	$ 35.57	2%	4,532
Vision	$ 14.21	$ 12.91	10%	3,369

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-103
Regarding 6+6 Adjustment, WP#14, please provide all supporting calculations, workpapers, and documentation for the customer education costs of $106,500.

RESPONSE:

The amount that the Company included in the filing for gas customer education costs is an estimate. The anticipated timing to implement gas decoupling is at the end of this gas base rate case, and the Company will be engaging in education of customers at that time. The breakdown of costs are as follows:

$ 45,000 – Newspaper Ad regarding gas decoupling
$ 61,500 - direct mailing of decoupling educational material

$106,500

Respondent: W. Michael VonSteuben

PSC DOCKET NO. 10-237
DE PSC STAFF'S FOLLOW UP ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-273
Refer to the response to DPA-103. a. Please provide the "decoupling educational material" that was direct mailed to customers. b. Provide the newspaper ad(s) for decoupling that cost $45,000. c. Has any of the $106,500 been spent yet? If so, when and how much?

RESPONSE:

a. As stated in the response to DPA-103, the anticipated timing of implementation of gas decoupling is at the conclusion of this case, therefore, no decoupling educational materials have been mailed to customers yet. These costs are estimates.

b. As stated in the response to DPA-103, the anticipated timing of implementation of gas decoupling is at the conclusion of this case, therefore, no newspaper ads have been placed yet. These costs are estimates.

c. No.

Respondent: W. Michael VonSteuben

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-53
Provide the amount of meals expenses included in the Test Period but disallowed for tax purposes.

RESPONSE:

See the attachment.

Respondent: W. Michael VonSteuben

DPA-53

DELMARVA & LIGHT COMPANY
12 MONTHS ENDING 2010

MEAL & ENTERTAINMENT

		AMOUNT	50%
1	April-08	24,868	12,434
2	May-08	31,157	15,578
3	June-08	27,534	13,767
4	July-08	19,196	9,598
5	August-08	28,235	14,118
6	September-08	46,439	23,219
7	October-08	31,365	15,683
8	November-08	9,843	4,921
9	December-08	20,486	10,243
10	January-09	11,945	5,973
11	February-09	11,992	5,996
12	March-09	17,957	8,978
		281,018	140,509

DPA-53

DELMARVA & LIGHT COMPANY
12 MONTHS ENDING 2010

MEAL & ENTERTAINMENT

		TOTAL AMOUNT	50%	Electric
1	July-09	11,607	5,803	5,397
2	August-09	28,203	14,101	13,114
3	September-09	30,815	15,407	14,329
4	October-09	14,575	7,288	6,778
5	November-09	24,325	12,162	11,311
6	December-09	50,534	25,267	23,498
7	January-10	16,153	8,077	7,511
8	February-10	111,334	55,667	51,770
9	March-10	44,379	22,190	20,636
10	April-10	33,415	16,707	15,538
11	May-10	35,440	17,720	16,480
12	June-10	61,962	30,981	28,812
		462,741	231,370	215,174

DPA-53

DELMARVA & LIGHT COMPANY
12 MONTHS ENDING 2010

MEAL & ENTERTAINMENT

		TOTAL AMOUNT	50%	GAS
1	July-09	11,607	5,803	406
2	August-09	28,203	14,101	987
3	September-09	30,815	15,407	1,079
4	October-09	14,575	7,288	510
5	November-09	24,325	12,162	851
6	December-09	50,534	25,267	1,769
7	January-10	16,153	8,077	565
8	February-10	111,334	55,667	3,897
9	March-10	44,379	22,190	1,553
10	April-10	33,415	16,707	1,170
11	May-10	35,440	17,720	1,240
12	June-10	61,962	30,981	2,169
		462,741	231,370	16,196

PSC DOCKET NO. 10-237
DE PSC STAFF'S FOLLOW UP ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-248
Refer to the response to DPA-53. a. Explain the increase in the meals and entertainment expense from $281,018 for the 12 months ended March 2009 to $462,741 for the 12 months ending June 2010. b. Provide comparable amounts for calendar years, 2007, 2008 and 2009. c. Identify the Gas amount for the monthly meals and entertainment tax disallowance amounts for the 12 months ended March 2009. d. In what account did DPL record the meals and entertainment for the 12 months ending June 30, 2010? Show the amounts recorded in each account.

RESPONSE:

a. The increase is due primarily to meals associated with the 2010 winter snowstorms and the June 2010 strike.
b. See the attachment.
c. Refer to the response to PSC-LA-249.
d. See the attachment for list of FERC accounts where the total DPL meals and entertainment expenses (both electric and gas portion) were charged for the 12 months ended June 30, 2010.

Respondent: W. Michael VonSteuben

DELMARVA & LIGHT COMPANY
12 MONTHS ENDING 2010
DE GAS CASE 10-237 Question No. : PSC-LA 248(b)
MEAL & ENTERTAINMENT

		A	B	C	D	E
		B+C+D				*A*.50*
		TOTAL AMOUNT	2007	2008	2009	50%
1	JANUARY	65,044	25,066	28,033	11,945	32,522
2	FEBRUARY	53,527	21,377	20,157	11,992	26,763
		-				
3	MARCH	64,911	15,922	31,032	17,957	32,456
		-				
4	APRIL	65,263	25,461	24,868	14,934	32,632
		-				
5	MAY	78,079	23,221	31,142	23,716	39,039
		-				
6	JUNE	66,245	22,279	27,549	16,416	33,122
		-				
7	JULY	43,301	12,499	19,196	11,607	21,651
		-				
8	AUGUST	75,816	19,378	28,235	28,203	37,908
		-				
9	SEPTEMBER	105,041	27,787	46,439	30,815	52,520
		-				
10	OCTOBER	66,363	20,422	31,365	14,575	33,181
		-				
11	NOVEMBER	53,863	19,696	9,843	24,325	26,931
		-				
12	DECEMBER	97,917	26,882	20,501	50,534	48,958
		$ 835,369	$ 259,990	$ 318,360	$ 257,018	$ 417,684

DELMARVA & LIGHT COMPANY
12 MONTHS ENDING 2010
DE GAS CASE 10-237 Question No. : PSC-LA 248(b)
MEAL & ENTERTAINMENT

		A	B	C	D	E	F
		B+C+D				*A*.50*	*E*.93*
		TOTAL AMOUNT	**2007**	**2008**	**2009**	50%	**Electric**
1	JANUARY	65,044	25,066	28,033	11,945	32,522	30,245
2	FEBRUARY	53,527	21,377	20,157	11,992	26,763	24,890
		-					
3	MARCH	64,911	15,922	31,032	17,957	32,456	30,184
		-					
4	APRIL	65,263	25,461	24,868	14,934	32,632	30,347
		-					
5	MAY	78,079	23,221	31,142	23,716	39,039	36,307
		-					
6	JUNE	66,245	22,279	27,549	16,416	33,122	30,804
		-					
7	JULY	43,301	12,499	19,196	11,607	21,651	20,135
		-					
8	AUGUST	75,816	19,378	28,235	28,203	37,908	35,255
		-					
9	SEPTEMBER	105,041	27,787	46,439	30,815	52,520	48,844
		-					
10	OCTOBER	66,363	20,422	31,365	14,575	33,181	30,859
		-					
11	NOVEMBER	53,863	19,696	9,843	24,325	26,931	25,046
		-					
12	DECEMBER	97,917	26,882	20,501	50,534	48,958	45,531
		$ 835,369	$ 259,990	$ 318,360	$ 257,018	$ 417,684	$ 388,446

DELMARVA & LIGHT COMPANY
12 MONTHS ENDING 2010
DE GAS CASE 10-237 Question No. : PSC-LA 248(b)

MEAL & ENTERTAINMENT
NOTE -- All amounts are pre-tax

		A	B	C	D	E	F
		B+C+D				*A*.50*	*E*.07*
		TOTAL AMOUNT	**2007**	**2008**	**2009**	50%	GAS
1	JANUARY	65,044	25,066	28,033	11,945	32,522	2,277
2	FEBRUARY	53,527	21,377	20,157	11,992	26,763	1,873
3	MARCH	64,911	15,922	31,032	17,957	32,456	2,272
4	APRIL	65,263	25,461	24,868	14,934	32,632	2,284
5	MAY	78,079	23,221	31,142	23,716	39,039	2,733
6	JUNE	66,245	22,279	27,549	16,416	33,122	2,319
7	JULY	43,301	12,499	19,196	11,607	21,651	1,516
8	AUGUST	75,816	19,378	28,235	28,203	37,908	2,654
9	SEPTEMBER	105,041	27,787	46,439	30,815	52,520	3,676
10	OCTOBER	66,363	20,422	31,365	14,575	33,181	2,323
11	NOVEMBER	53,863	19,696	9,843	24,325	26,931	1,885
12	DECEMBER	97,917	26,882	20,501	50,534	48,958	3,427
		$ 835,369	$ 259,990	$ 318,360	$ 257,018	$ 417,684	$ 29,238

PSC-LA-248 d
Attachment

DPL record of meals and entertainment by FERC accounts for 12 months ended 6-30-2010

Regulated Account	Amount
910700	65,509.01
941600	2,207.80
941710	5,355.50
942640	8,213.87
955700	13.14
956000	807.52
956110	542.44
956120	2,710.69
956130	279.06
956600	3,700.30
956920	38.16
957000	2,710.97
957100	549.15
957200	194.82
957300	675.04
958000	16,330.40
958100	5,906.53
958200	126.19
958300	1,460.04
958400	942.92
958500	54.58
958600	4,311.54
958700	4.10
958800	40,385.36
959000	62.72
959200	4,248.27
959300	89,685.59
959400	1,737.64
959600	583.08
959700	226.96
959800	1,229.44
980700	53.95
981300	12.75
984000	10.89
984100	678.26
984220	1.59
984310	35.27
984320	27.62
984340	1.44
984350	69.14
984360	96.82
984370	6.23
984380	0.25
984390	42.00
985000	10.01
985100	432.95
985600	82.85
985700	79.35

PSC-LA-248 d
Attachment

DPL record of meals and entertainment by FERC accounts
for 12 months ended 6-30-2010

Regulated Account	Amount
985900	95.20
986000	1.21
986300	617.02
986500	93.30
987000	51.47
987100	237.61
987400	2,288.66
987500	168.07
987800	1,516.83
987900	1.04
988000	3,667.18
988700	648.69
988800	57.79
988900	119.49
989200	1,109.16
989300	1,653.74
989400	133.13
990200	5,843.34
990300	4,648.83
990800	1,207.40
991300	430.01
992100	110,920.10
992300	412.91
992600	0.02
992800	906.85
992900	216.10
993020	(1,192.63)
993500	683.84
Clearing cost centers	63,760.20
	462,740.76

PSC DOCKET NO. 09-414 & 09-276T
STAFF'S ACCOUNTING SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-A-24
Provide a detailed description of all efforts by the Company to manage and reduce the amount of uncollectibles from 2003 to 2009. Include supporting documentation.

RESPONSE:

The Company has engaged in some efforts to reduce its uncollectibles from 2003 through 2009. Below are listed the major activities that have taken place during that time period:

- Match-Up Report (transfer uncollectibles balances to eligible accounts) –This is a new (2008) report based on the expansion of the previous Credit Check Exception Report. The Match-Up Report provides the Company the ability to associate existing overdue balances with new customer sign-ups through the matching of Social Security Numbers for residential customers and SSN and/or Tax ID number for non-residential customers. Through the use of these identifiers, the Company has reduced the amount of uncollected revenue from those customers who would use an alias to defraud the company of appropriately billoed revenues.
- Account Deposit Policy and Procedure – While the Company did not make any changes in its policy and/or procedures with respect to account deposits, it has become more vigilant in adhering to the stated policies and procedures.
- Sold receivables to third party - In March, 2007 Delmarva Power sold $23.6MM in uncollectible debts to Arrow Financial services. This was a one-time project /effort to improve the collections by selling these to an outside agency and has not been repeated since.

Respondent: W. Michael VonSteuben

PSC DOCKET NO. 09-414 & 09-276T
STAFF'S ACCOUNTING SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-A-25
Provide a quantification of reductions in uncollectibles resulting from efforts by the Company to manage and reduce the amount of uncollectibles from 2003 to 2009.

RESPONSE:

Quantification of Reductions in Uncollectibles from '03-'09:

YEAR	RECOVERED	PAID TO AGENCY
2009(YTD Nov)	$2,314,000	$343,000
2008	$2,377,000	$431,000
2007	$2,070,000	$376,000
2006	$2,172,000	$318,000
2005	$1,947,950	$305,000
2004	$2,019,040	$296,000
2003	n/a	n/a

- Efforts to manage and reduce uncollectibles include:
  - Company disconnect/collection process
  - Dunning Process
  - Agency Referral, if applicable
  - Bankruptcy Maintenance Follow-up
  - Tax ID Match up – new same as SSN Tax ID for commercial if no SSN

As indicated in PSC-A-22, these dollar amounts include both electric and gas as the Company does not separate these two components for this activity.

Respondent: W. Michael VonSteuben

PSC DOCKET NO. 10-237
DE PSC STAFF'S FIRST SET OF ACCOUNTING DATA REQUESTS
TO DELMARVA POWER & LIGHT COMPANY

Question No. : PSC-LA-92
Stock-Based Compensation. a. List, by amount and account, all stock-based compensation expense charged to DPL during the test year, including but not limited to executive stock options, performance share awards, accruals made pursuant to Statement of Financial Accounting Standards (SFAS) 123R and any other stock-based compensation awards that resulted in costs being charged to DPL during the test year. b. Describe each distinct stock-based compensation program that resulted in charges to DPL during the test year. c. Explain fully and in detail the amount of stock-based compensation that DPL has included in cost of service for the test period ended June 30, 2010.

RESPONSE:

a) Stock-based compensation is charged to General Ledger Account 710036 – "Salaries – LITP/PARS". For the test period, DPL's costs recorded to General Ledger Account 710036 were $45,112.
b) See PHI's 2009 Proxy Statement and Annual Report to Stockholders page 28 – 30 for a description of the long term incentive plan.
c) Gas Expense for the test period is:

DPL	
Total DPL Cost	$45,112
Allocation % (Gas Expense % of Total DPL Cost%)	12.17%
Total Gas Expense	$ 5,492
Service Company	
Total Service Company Cost	$3,925,949
Expense Allocation % (of Service Company Total)	83.22%
DPL Allocation % (of Service Company Total)	26.28%
Gas Allocation % (of DPL Total)	19.00%
Total Gas Expense	$163,138
Gas Expense Total – DPL & Service Company	$168,630

Respondent: Ernest L. Jenkins/W. Michael VonSteuben

PSC DOCKET NO. 10-237
DIVISION OF THE PUBLIC ADVOCATE
FIRST SET OF DATA REQUESTS TO
DELMARVA POWER & LIGHT COMPANY

Question No. : DPA-23
Fully describe any SERP benefits, quantify any SERP costs included in the Company's filing and describe how the Company's claim for SERP costs was determined.

RESPONSE:

See PHI's Proxy Statement and 2009 Annual Report to Shareholders – pages 51 and 52 for description of SERP benefits.

See the attachment for Gas SERP expense included in test period cost of service.

Respondent: Ernest L. Jenkins/W. Michael VonSteuben

DELMARVA POWER & LIGHT COMPANY **DPA-23**
SERP EXPENSE - GAS
FROM JULY 2009 - JUNE 2010

	JULY 2009 - DECEMBER 2009	JANUARY 2010 - JUNE 2010	TOTAL
DPL - DIRECT			
TOTAL	$302,831	$329,040	
GAS EXPENSE % OF TOTAL $	12.28%	12.17%	
TOTAL	$37,188	$40,044	$77,232
PHI SERVICE COMPANY - $ ALLOCATED TO DPL			
TOTAL	$358,538	$351,463	
GAS % OF DPL	19.00%	19.00%	
GAS EXPENSE % OF TOTAL $	84.23%	83.22%	
TOTAL	$57,379	$55,573	$112,952
TOTAL - DPL-DIRECT & PHI SERVICE COMPANY ALLOCATION			$190,184

Excerpts from NARUC-Sponsored Audits of the Expenditures of the American Gas Association

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31,1999)

JUNE 2001

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

**National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005**

Telephone No. (202) 1898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31,1999

EXPENSE CATEGORY	PERCENTAGE
Public Affairs	15.43%
Communications	11.64%
Media Communications:	
Commercial Equipment	4.47%
Environmental	0.74 %
Promotional	0.74%
Residential Equipment	2.96%
Corporate Affairs & International	11.30%
General Counsel & Corporate Secretary	4.02%
Regulatory Affairs	11.20%
Marketing Services	15.02%
Operating & Engineering Services	14.70%
Policy & Analysis	12.07%
Industry Finance & Admin. Programs	2.94 %
General & Administrative Expense	0.00%
TOTAL	107.23% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1999

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (5)	Adjusted Net Expense	% of Dues
03	Public Affairs	4,147,682	3, 4	(1,690,669)	455,752	2,912,765	15.43%
03	Communications		4	1,698,695	498,479	2,197,174	11.64%
08	Media Communications						
	Commercial Equipment	759,932	1,2	61,868	21,400	843,200	4.47%
	Environmental	126,708	1,2	10,316	3,568	140,592	0.74%
	Promotional	126,708	1,2	10,316	3,568	140,592	0.74%
	Residential Equipment	503,934	1,2	41,027	14,191	559,152	2.96%
06. 16	Corporate Affairs and International	1,483,688	3	(5,217)	655,144	2,133,615	11.30%
05	General Counsel & Corp. Secretary	588,436	3		170,907	759,343	4.02%
09	Regulatory Affairs	1,492,676	3	194,393	427,268	2,114,337	11.20%
08	Marketing Services	4,654,503	1, 2	(2,302,920)	484,237	2,835,820	15.02%
14	Operating & Engineering Services	1,949,534			826,051	2,775.585	14.70%
07	Policy & Analysis	1,374,743	1	277.704	626,659	2,279,106	12.07%
12	Industry Finance & Admin. Programs	498,349			56,969	555,318	2.94%
01.10.11	General & Administrative Expense	4,247,002	3	(2,809)	(4,244,193)		0.00%
	Grand Total	21,953,895		$ (1,707,296)	$ -	$ 20,246,599	107.23%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 Breakout of communications portion of division expenses
5 G&A allocated on basis of equivalent full-time employees during 1999.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1999

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
	Public affairs provides members with information on legislative developments: prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.
08	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
	Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applicationsof specific equipment.
	Institutional - to enhance the image of the natural gas industry as a business entity.
	Power Generation Natural Gas Equipment - explains cost-savings. energy-savings and other benefits provided by specific equipment for generating power.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
12	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.

05 General Counsel & Corporate Secretaw provides legal counsel to the Association

06 Corporate Affairs provides opportun'ities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

09 Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

08 Market Development assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

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AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 1998)

JANUARY 2000

COMMITTEE ON UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue, N.W., Suite 200
Washington, D.C. 20005

Telephone No. (202) 898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 1998

EXPENSE CATEGORY	PERCENTAGE
Communications	10.27%
MEDIA COMMUNICATIONS:	
Commercial Equipment	5.96%
Environmental	3.37%
Industrial Equipment	1.36%
Promotional	1.46%
Residential Equipment	8.40%
Finance & Administration Services	12.17%
General Counsel & Corporate Secretary	5.54%
Government Relations	23.86%
Marketing Services	16.20%
Meeting Services	-0.18%
Operating & Engineering Services	4.90%
Planning & Analysis	9.51%
General & Administrative Expense	0.00%
TOTAL	102.82% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1998

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (4)	Adjusted Net Expense	% of Dues
03	Communications	1,561,612	2	(2,679)	430,782	1,989,715	10.27%
13	Media Communications						
	Commercial Equipment	1,105,739	1,2	31,943	17,848	1,155,530	5.96%
	Environmental	625,598	1,2	18,072	10,098	653,768	3.37%
	Industrial Equipment	252,954	1,2	7,307	4,083	264,344	1.36%
	Promotional	270,820	1,2	7,823	4,372	283,015	1.46%
	Residential Equipment	1,557,378	1,2	44,990	25,139	1,627,507	8.40%
06	Finance & Administration Services	1,797,937	3	(13,893)	574,377	2,358,420	12.17%
05	General Counsel & Corp. Secretary	938,797	3	(8,566)	143,594	1,073,825	5.54%
09	Government Relations	3,802,555	3	22,459	800,025	4,625,039	23.86%
08	Marketing Services	2,693,462	1	(107,456)	553,863	3,139,869	16.20%
04	Meeting Services	(34,155)		-	-	(34,155)	-0.18%
14	Operating & Engineering Services	661,825		-	287,188	949,013	4.90%
07	Policy & Analysis	1,392,718		-	451,296	1,844,014	9.51%
01,10,11	General & Administrative Expense	3,302,665		-	(3,302,665)	0	0.00%
	Grand Total	19,929,905		$ 0	$ 0	$ 19,929,905	102.84%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.
1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 G&A allocated on basis of equivalent full-time employees during 1997.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1998

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
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	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applications of specific equipment.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
06/16	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.
05	General Counsel & Corporate Secretary provides legal counsel to the Association.
09	Government Relations provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.
08	Marketing assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

04 Meeting Services and Membership Services provides support services for committee meetings and conferences. In addition, coordinates services provided to members.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Excerpt from a Florida Public Service Commission Staff Memorandum in a City Gas Company Rate Case Addressing AGA Dues – December 23, 2003

Excerpt from Florida PSC City Gas Company rate case 01152004

State of Florida

Public Service Commission

Capital Circle Office Center 2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE:DECEMBER 23, 2003

TO:DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM:DIVISION OF ECONOMIC REGULATION (BRINKLEY, BAXTER, DRAPER, GARDNER, HEWITT, KAPROTH, KENNY, LESTER, LINGO, C. ROMIG, SPRINGER, STALLCUP, WHEELER, WINTERS)
DIVISION OF COMPETITIVE SERVICES (MAKIN)
OFFICE OF THE GENERAL COUNSEL (JAEGER)

RE:DOCKET NO. 030569-GU - APPLICATION FOR RATE INCREASE BY CITY GAS COMPANY OF FLORIDA.

AGENDA:01/06/04 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES:5-MONTH EFFECTIVE DATE: JANUARY 15, 2004 (PAA RATE CASE)

SPECIAL INSTRUCTIONS:NONE

FILE NAME AND LOCATION:S:\PSC\ECR\WP\City Gas 030569-GU\
Final.RCM
Final Attachments 1-5.123
Final Attachments 6A-7P.123
Final Attachment 8.xls

ISSUE 39: Is City Gas's $(2,847) adjustment to Account 921, Office Supplies and Expenses, for American Gas Association membership dues appropriate?

RECOMMENDATION: No. Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for American Gas Association membership dues related to charitable contributions and advertising that is not informational or educational in nature. (C. ROMIG)

STAFF ANALYSIS: On MFR Schedule G-2, Page 17 of 34, the Company included $1,966,495 in its Account 921, Office Supplies and Expense for the 2003 interim year. Included in this amount is $39,277 related to American Gas Association (AGA) membership dues. This was inflated for customer growth and general inflation of 1.0232 to $40,188. On MFR G-2, Page 2 of 34, it removed $2,847 that was labeled as "attributable to lobbying." This represents an adjustment of 7.08%.

In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR A CHANGE IN NATURAL GAS BASE RATES (FILED JULY 2, 2010)	))))	PSC DOCKET NO. 10-237

CERTIFICATE OF SERVICE

Regina A. Iorii hereby certifies that on October 28, 2010, she caused a copy of the following to be served on all parties in this docket in the manner indicated on the attached service list:

- **DIRECT TESTIMONY AND EXHIBITS OF HOWARD SOLGANICK ON BEHALF OF THE STAFF OF THE PUBLIC SERVICE COMMISSION**
- **DIRECT TESTIMONY OF RALPH C. SMITH ON BEHALF OF THE COMMISSION STAFF**

Regina A. Iorii

Regina A. Iorii
Deputy Attorney General
Delaware Public Service Commission
820 N. French Street, 6th Floor
Wilmington, DE 19801
(302) 577-8159 (Wilmington)
(302) 736-7510 (Dover)
regina.iorii@state.de.us

Dated: October 28, 2010

PSC DOCKET NO. 10-237

SERVICE LIST

<u>Hearing Examiner</u> Ruth Ann Price Senior Hearing Examiner Delaware Public Service Commission 861 Silver Lake Blvd., Suite 100 Dover, Delaware 19904 Phone: 302-736-7540 (Dover) 302-577-5014 (Wilmington) Fax: 302-739-4849 (Dover) 302-577-2694 (Wilmington) E-mail: ruth.price@state.de.us **<u>PSC Staff</u>** Susan B. Neidig, Senior Reg. Policy Admin. Courtney A. Stewart, Public Utilities Analyst Delaware Public Service Commission 861 Silver Lake Blvd., Suite 100 Dover, Delaware 19904 Phone: 302-736-7527 (Neidig) 302-736-7532 (Stewart) Fax: 302-739-4849 E-mail: susan.neidig@state.de.us courtney.stewart@state.de.us	**<u>PSC Staff Counsel</u>** Regina A. Iorii, Staff Counsel Deputy Attorney General-Civil Delaware Public Service Commission Carvel State Office Bldg. 820 N. French Street Wilmington, Delaware 19801 Phone: 302-577-8159 (Wilmington) 302.736-7510 (Dover) Fax: 302.739-4849 E-mail: regina.iorii@state.de.us **<u>PSC Staff Counsel</u>** Joseph C. Handlon, Esquire Deputy Attorney General – Civil Delaware Public Service Commission 861 Silver Lake Boulevard, Suite 100 Dover, DE 19904 Telephone: 302-736-7558 Fax: 302-739-4849 E-mail: joseph.handlon@state.de.us
<u>PSC Staff Consultant</u> Howard Solganick Energy Tactics & Services, Inc. 810 Persimmon Lane Langhorne, PA 19047 Phone: 215-378-2280 Fax: E-mail: howard@energytactics.com	**<u>PSC Staff Consultant</u>** Ralph Smith Larkin & Associates, PLLC 15728 Farmington Road Livonia, MI 48154 Phone: 734- 522-3420 Fax: 734- 522-1410 E-mail: rsmithla@aol.com
<u>PSC Staff Consultant</u> James Rothschild Rothschild Financial Consulting 115 Scarlet Oak Dr. Wilton, CT 06897 Phone: 203-762-8090 Fax: 203-834-2634 E-mail: jimrothschild@rothschildfinancial.com	**<u>Division of the Public Advocate Counsel</u>** Kent Walker, Esq. Deputy Attorney General 820 N. French Street, 6th Floor Wilmington, Delaware 19801 Phone: 302-577-8306 Fax: 302-577-6630 E-mail: kent.walker@state.de.us

Division of the Public Advocate	Division of the Public Advocate Consultant
G. Arthur Padmore, Public Advocate (PA) Michael D. Sheehy, Deputy PA Division of the Public Advocate 820 N. French Street, 4th Floor Wilmington, DE 19801 Tele: 302-577-5077 (Padmore) 302-577-5078 (Sheehy) Fax: 302-577-3297 E-mail: arthur.padmore@state.de.us michael.sheehy@state.de.us	Andrea C. Crane The Columbia Group, Inc. Mailing Address: P.O. Box 810 Georgetown, CT 06829 Overnight Mailings: 199 Ethan Allen Highway, 2nd Floor Ridgefield, CT 06877 Phone: 203-438-2999 Fax: 203-894-3274 E-mail: CTColumbia@aol.com
Delmarva Power & Light Company Counsel Todd L. Goodman, Esquire Associate General Counsel Delmarva Power & Light Company Mailing address: P. O. Box 231 Wilmington, DE 19899-0231 Overnight Mailings: 800 King Street Wilmington, DE 19801 Phone: 302-429-3786 Fax: 302-429-3801 E-mail: todd.goodman@pepcoholdings.com	**Delmarva Power & Light Company** Heather G. Hall Delmarva Power & Light Company Regulatory Affairs Mailing address: P.O. Box 9239 Newark, DE 19714-9239 Overnight Mailings: 401 Eagle Run Road Newark, DE 19702 Telephone: 302-454-4828 Fax: 302-454-4440 E-mail: heather.hall@pepcoholdings.com
Delmarva Power & Light Company W. Michael VonSteuben Delmarva Power & Light Company Regulatory Affairs Mailing address: P.O. Box 9239 Newark, DE 19714-9239 Overnight Mailings: 401 Eagle Run Road Newark, DE 19702 Telephone: 302-454-4872 Fax: 302-454-4440	**Delmarva Power & Light Company** **By e-mail only:** pamela.long@pepcoholdings.com joseph.janocha@pepcoholdings.com

E-mail: mike.vonsteuben@pepcoholdings.com	
Representative John A. Kowalko, Jr. 124 N. Dillwyn Road Newark, DE 19711 Phone: 302-737-2396 (home) 302-547-9351 (cell) 302-577-8342 (office) john.kowalko@state.de.us	