# BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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| In Re: Petition for Rate Increase by Peoples Gas System | ) ) ) | Docket No. 080318-GU<br>Filed: December 18, 2008 |

## DIRECT TESTIMONY OF HELMUTH W. SCHULTZ, III

## ON BEHALF OF THE CITIZENS OF FLORIDA

Respectfully submitted,

J.R. Kelly
Public Counsel

Office of the Public Counsel
c/o The Florida Legislature
111 West Madison Street
Room 812
Tallahassee, FL 32399-1400

Attorney for the Citizens
of the State of Florida

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PEOPLES GAS SYSTEM

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## I. INTRODUCTION

Q. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Helmuth W. Schultz, III. I am a Senior Regulatory Analyst in the firm of Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES, PLLC.

A. Larkin & Associates, PLLC, is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorney general, etc.). Larkin & Associates, PLLC, has extensive experience in the utility regulatory field as expert witnesses in more than 800 regulatory proceedings including numerous electric, water and sewer, gas and telephone utilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FLORIDA PUBLIC COMMISSION?

A. Yes. I have testified before the Florida Public Service Commission on a number of occasions during the last 32 years.

Q. HAVE YOU PREPARED AN APPENDIX WHICH DESCRIBES YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Appendix I which is a summary of my regulatory qualifications and experience.

Q. BY WHOM WERE YOU RETAINED?

A. Larkin & Associates, PLLC, was retained by the Florida Office of Public Counsel ("OPC"). Accordingly, I am appearing on behalf of the Citizens of Florida ("Citizens").

## II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Our firm was asked by the Public Counsel to analyze the $26,488,091 rate increase requested by Peoples Gas and provide our analysis of what rate increase is justified. The increase requested amounts to a 15.6% increase in base rates over the projected 2009 base rate revenue. This increase would be in addition to the fuel cost increases already being passed on to ratepayers.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS AND WHAT IS YOUR RECOMMENDATION REGARDING PEOPLES' RATE INCREASE?

A. We are recommending that the Company has not justified a rate increase of more than $5,673,535 for the Peoples Gas. This recommendation is shown on my Exhibit HWS-1, Schedule A-1, Line 8. My exhibit incorporates the recommendations of Dr. J. Randall Woolridge.

Q. HOW WOULD YOU CHARACTERIZE THE COMPANY'S REQUESTED INCREASE?

A. I would characterize the Company's filing as excessive. The Company has included a number of costs that are not justified and over-statements of cost estimates that have added significantly to the Company's revenue requirement request.

Q. WHAT PARTICULAR REQUESTS DO YOU VIEW AS THE MOST PROBLEMATIC?

A. There are number of problems and/or concerns with the Company's requests included in the filing. The following are specific concerns:

1) The Company is requesting that a portion of uncollectibles expense be transferred to the Purchase Gas Adjustment (PGA) Clause.
2) The Company is requesting a Gas System Reliability Rider (GSR) to recoup the capital costs of government-mandated relocations of Peoples' facilities and reimbursement of gas safety operation and maintenance expenses without having to go through the review of a rate case.
3) The Company is requesting a mechanism that would allow the Company to recover costs of expand its system to future proposed developments without a rate case, which it is calling a Carbon Reduction Rider (CR).
4) Plant additions include costs for pipe installation at a cost per foot that is significantly different than the actual 2008 costs per foot.
5) Peoples has requested to continue the sharing mechanism for Off-System Sales without any change to the base revenue factor. Continuing the sharing plan "as is" ignores the fact that historically the Company has significantly, on an annual basis, exceeded the $500,000 base revenue factor.
6) Peoples is requesting costs for Pipeline Integrity improvements without having sufficient information to be able to know with certainty what the costs will be.
7) The filing includes other costs that are not justified, excessive and/or not appropriate costs to be borne by ratepayers.

8) Peoples has not included a parent debt adjustment as required by Commission Rule 25-14.004, Florida Administrative Code.

## III. UNCOLLECTIBLES RECOVERY

Q. WHAT IS THE PROBLEM WITH ALLOWING A PORTION OF UNCOLLECTIBLES TO BE INCLUDED IN THE COMPANY'S PGA?

A. Uncollectible accounts receivables require special attention from the Company. The shifting of a substantial portion of the uncollectible costs to the PGA would provide the Company virtually an automatic pass-through while unreasonably assuming that the Company will continue to use all the resources available to recover the account receivables that are in question. Without an automatic pass-through, the Company is required to provide every effort to minimize the level of write-offs between rate cases. That effort can be rewarded by the Company having to write-off an amount that is less than what has been used as a target in setting rates during a rate case. An automatic pass-through will take away the incentive to make every effort to collect the funds that are delinquent. If the write-offs are recovered immediately through the PGA then there no longer is a need to minimize the level of write-offs. The regulatory process is designed to provide for oversight and provides an incentive to perform at optimal levels. The allowance of the pass-through for traditional base rate type costs like uncollectibles takes away from that oversight and the Company's need to perform.

There is also the fact that despite the volatility in gas prices in recent years the level of uncollectibles has not had a commensurate increase with the increase in gas costs. In fact, in 2007, the actual net write-offs declined significantly.

As will be discussed in more detail later, allowing the Company another automatic recovery mechanism reduces shareholder risk and absent a concomitant decrease in the return on equity, shareholders will be unjustly enriched at rate-payers expense. The Company's adjustment to remove the $723,580 from O&M expense should be reversed.

## IV. GAS SYSTEM RELIABILITY RIDER

Q. PLEASE DESCRIBE THE COMPANY'S REQUESTED GSR RIDER.

A. Peoples has designed the Gas System Reliability Rider (GSR) to provide increased rates for recovery of the capital investment associated with government-mandated relocations of Peoples' facilities and the incremental cost of gas safety operation and maintenance expenses in between rate cases. The gas safety O&M costs are also referred to by Company witness Higgins as pipeline integrity costs. While the projected test year includes costs associated with line relocations and gas safety, the Company wants an additional mechanism to guarantee recovery of these incremental costs outside of base rates beginning in 2010, after the new base rates are placed into effect. Regarding the gas safety O&M expenses, the Company wants an annual true-up if the costs exceed the $750,000 cost included for base recovery in this docket.

Q. WHAT IS THE PRIMARY PROBLEM WITH ALLOWING THE COMPANY A GSR MECHANISM?

A. The primary problem in the requested recovery mechanism is the Company's contention that it will not recover these costs outside of base rate relief unless it receives this annual rate increase. As long as the Company earns sufficient net income to keep its overall rate of return within the range of its authorized range, the Company will recover its investment in these costs. If the Company is earning within its range and then is allowed to have certain normal base rate type costs shifted to clause recovery, then the Company could, in effect, be placed in an overearnings posture. This is basic regulatory theory and is the reason why the company and its shareholders are compensated for this risk through the rate of return on equity.

Q. ARE THERE OTHER PROBLEMS WITH THIS RECOVERY MECHANISM?

A. Yes. The Company claims that the GSR will help manage the substantial investments the Company must make each year due to government-mandated relocations of Company facilities. As discussed further in my testimony, the statement that the costs are substantial is misleading. Moreover, the rider will not have any positive impact on the management of the investments associated with the relocation of facilities. In fact the opposite may occur and management of the project may result in an increase in costs. The same argument is true for the government mandated incremental safety expenses that the Company will incur after the test year. Including recovery of these base rate incremental costs through an annual recovery mechanism will not provide a management incentive to reduce costs or seek proper reimbursement of these costs because it allows for the automatic pass-through of costs. In addition, the shortened regulatory timeframe associated with clause recovery allows the Company to diminish the regulatory scrutiny of its costs for reasonableness by regulators and ratepayers.

Q. WHY WOULD IT BE POSSIBLE THAT LESS PROJECT MANAGEMENT MAY OCCUR?

A. Currently, the Company is required to evaluate alternatives and make sound decisions because there is financial risk involved with the relocation of the facilities. The Company is forced to be cost conscious because there is the risk that the cost of the project may lessen the Company's earnings until the next rate case. With the pass-through mechanism the Company may not be as cost conscious in the decisions that need to be made. There is also the opportunity that the relocation could include costs for expansion of capacity that is not currently needed or may not be needed in the near future, but the Company might incur the cost anyway because the cost can be automatically passed through to customers by means of the recovery mechanism. There is also the possibility that with an automatic recovery mechanism, the Company may not explore all possibilities of reimbursement that may exist under Florida statutes.

Q. ARE THERE OTHER REASONS WHY THE GSR IS NOT APPROPRIATE?

A. Yes. The use of a mechanism for automatic recovery of costs is contrary to the principles underlying the regulatory process. The regulation of utilities allows for oversight by regulators that will provide ratepayers protection in a monopoly environment. This process also provides the utility the opportunity to earn a reasonable rate of return for its shareholders based on the risks that they are assuming. Prior to commencement of any clause recovery mechanisms, all costs were included in the standard base rate recovery ratemaking process. In the late 1970's, the Florida Public Service Commission moved away from full base rate recovery, by allowing recovery of fuel costs through a clause mechanism. The recovery mechanism was allowed because of the significance of the cost of fuel in relation to total costs and the volatility of the costs. The Purchased Gas Adjustment (PGA) remains in use currently on an annual basis particularly to allow for prompt recovery of this volatile expense and also to provide a current price signal for customers so that they are aware of how much an impact the cost of gas has on their total bill. For example, the cost of gas for Peoples' 2009 projected test year is $351 million or 71.8% of the $488 million of total operating expenses projected. That percentage alone is very significant and, in as much, the Commission has determined that gas costs warrant a separate recovery mechanism.

The Company has indicated that the annual capital costs for government mandated projects have averaged $4.28 million over the years 2003-2007. The Company's capital cost over the same period of time has averaged $44.8 million. The government-mandated project costs are less than 10% of the annual expenditures and that relationship is small in comparison to the gas costs being 71.8% of total operating expenses.

Q. PLEASE EXPLAIN THE GAS SAFETY COSTS THE COMPANY IS REQUESTING TO BE RECOVERED THROUGH THE GSR.

A. Peoples' witness Binswanger testified that the Company anticipates being faced with additional O&M expenses not covered in the projected test year in this case for pipeline safety mandates pursuant to the PIPES Act. It would also recover incremental O&M expenses incurred to comply with the federal transmission and distribution pipeline integrity requirements. Mr. Binswanger suggests that it is appropriate to approve the GSR rider because Peoples cannot predict the associated future gas safety expenses and will not be able to avoid these costs. Although Peoples has included $750,000 in test year expenses for gas safety, it still wants to add an annual clause in case its costs change after the rate case has concluded. I have addressed the reasonableness of the Company's test year projected expenses in the section of my testimony entitled Pipeline Integrity Expense.

Q. WHAT CONCERNS DO YOU HAVE REGARDING THE RECOVERY OF THE GAS SAFETY EXPENSES?

A. First, the Company clearly admits that these costs are base rate costs by including them in O&M expenses. It is inappropriate to ask for costs to be included in base rate and then suggest that future over and under amounts be trued up through a clause mechanism. Second, the expense amounts projected by the Company are minimal compared to the requested operating expenses of over $135 million for the Company.

Adding to this concern is the Company's request for a Carbon Reduction Rider (CR). The CR rider would provide a mechanism for recovery of the capital cost for supply mains to new developments. The creation of the two riders would increase the automatic recovery of capital costs above 10% and essentially reduce the risk for which shareholders are already being adequately compensated for as part of an allowed rate of return.

Q. HAS THE COMPANY PROVIDED ANY JUSTIFICATION FOR THE GSR?

A. No. In its response to OPC Interrogatory No. 59, the Company attempted to justify the GSR by claiming that this type of costs has increased over the past several years. It further claimed that absent a recovery mechanism the Company would be required to file a full rate case to recover the revenue requirements associated with the investments in plant. The facts do not support the Company's claims. The Company's costs have fluctuated from year to year. In 2001, the costs were $4.8 million. In 2002 and 2003, the costs were $4.6 million and $3.8 million, respectively. In 2005, the costs were up to $5.2 million but declined in 2006 to $2.9 million. The Company projected $6.3 million for 2008, but only $3.8 million is projected for 2009. There is no steady increase in costs as the Company suggests. The Company's second claim that it would have to file a full rate case is also without merit. The Company did not file a full rate case in 2005 when the costs reached $5.2 million. In fact, based on the level of the Company's incentive compensation payout over the target level budgeted for 2005, it appears that the costs incurred for relocations had no impact on financial results at all.

V. CARBON REDUCTION MECHANISM

Q. ARE YOUR CONCERNS WITH THE CR RIDER THE SAME AS THE CONCERNS YOU IDENTIFIED WITH THE GSR?

A. Yes. In addition, the risk of development should be placed on new customers and not the current customer base. Growth should pay for itself with the cost risk being assumed by those planning the development and/or the customers that will be served by the development. Moreover, the Company's response to Staff Interrogatory No. 38, indicates that the general body of ratepayers is not at risk if the development does not build out as planned because the developer agreements contain language that protects rate payers. If that assertion is in fact true, then there is no need for the recovery mechanism because the Company would not be at risk either. Also to be considered is the fact that based on the response to Staff Interrogatory No. 43, the average capital cost under the proposed rider for the years 2005-2007 is $436,943. That amount is not significant enough to justify an automatic recovery mechanism.

Q. HOW WOULD GROWTH PAY FOR ITSELF?

A. When rates are set, they are based on the plant and operating costs that are associated with a specific level of customers. New customers require new plant and some added operating expenses. The new customers will be paying the same rates as the old customers and that, in theory, should be sufficient to cover the costs of new plant and operating expenses. In fact, the rates from the new customers should provide an excess because there should be incremental gains from spreading the administrative costs over a greater number of customers.

Q. ARE THERE ANY OTHER REASONS WHY THE CR RIDER IS NOT APPROPRIATE?

A. Yes. The Company has projected a reduced percentage of new customers being added in 2008 and 2009. Because of the recessionary nature of today's economy, Florida is not seeing the aggressive development of new homes as it did in recent years. The market is not the same as it was in the past when the Company made it through a period of significant growth in the new homes market without a rate case or a recovery mechanism. There is no justification for allowing a mechanism for recovering the cost of supply mains to new developments. The Company's request should be denied.

Q. IS THERE A PROBLEM WITH ADDING THE THREE RECOVERY MECHANISMS REQUESTED BY THE COMPANY?

A. Yes. Allowing the multiple mechanisms to the Company, as they have requested, would be the equivalent of implementing single issue ratemaking without the appropriate oversight. The Company is trying to eliminate its financial risks that are factored in the allowed rate of return and eliminate the need for regulatory review. The more that certain costs are subject to recovery through some form of recovery mechanism, the less the Company is required to establish control over costs and the risk associated with managing costs is reduced. With a continual increase in automatic recovery mechanisms, the Company will not have a need to request any change in base rates because recovery is automatic. Peoples has not been in for a rate request since 2002, and before that the last Company initiated rate case was in 1992. The Company did have an earnings investigation where an order was issued in early 1998. What that indicates is the current process is working fine for ratepayers and the Company without any need for the addition of three new automatic recovery mechanisms that are now being requested. The government mandated relocations and gas safety expenditures are not something new, incurring costs associated with new development supply lines is not something new and bad debts have always been a part of the cost of service. This is a change in ratemaking that is not needed or justified.

Q. WHAT DO YOU RECOMMEND IF THE COMMISSION DETERMINES THERE IS SOME MERIT TO ALLOWING THE GSR OR THE CR?

A. If the Commission should decide that the two clauses would be beneficial to the Company and its shareholders, then the Commission should also factor that in their determination of what constitutes a reasonable rate of return. The shareholders' financial risks would be reduced because of the automatic pass-through; therefore, a similar reduction would need to be made to the allowed rate of return to account for the reduced risk. If the Commission does not reduce the rate of return, the Company will essentially be allowed to over-recover their cost of service. Ratepayers should not have to provide guaranteed annual recovery of incremental investment and normal operating costs already provided for by base rate recovery and also pay a risk premium as part of the rate of return being allowed.

Q. WILL THE IMPLEMENTATION OF THE COMPANY'S REQUESTED TWO NEW RIDERS IMPACT COSTS TO THE RATEPAYERS AND THE COMMISSION?

A. Yes. Both of these two new clauses that the Company refers to as riders to its tariff will increase costs to customers as well as the Commission. First, the implementation of the clauses will involve additional regulatory filings as described in detail in the company's tariff pages 7.807 and 7.809. Not only will this increase costs to customers, but this will greatly impact the amount of work that the Commission will have to undertake to analyze and approve the filings. The tariff pages essentially mandate the Commission to analyze and consider the annual cost and clause components. The tariff wording is written similar to a statute or rule, and goes so far as to substantially limit the Commission's discretion regarding the approval of the annual rider/clause filings. The filings will create an additional workload and cost on top of those required by the 6 clause mechanisms already approved by the Commission for all of the electric and gas companies.

Q. BASED ON YOUR ANALYSIS, HAS THE COMPANY SHOWN THAT THE APPROVAL OF THESE TWO NEW CLAUSE RECOVERY MECHANISMS ARE PRUDENT OR NECESSARY?

A. No it has not. These costs are base rate costs as the Company has shown by the inclusion of these costs in its projected plant and expenses. Further, the Company is attempting to create two new clauses where no regulatory benefit exists and only serves to increase costs to ratepayers and to the Commission. In these difficult economic times, increasing costs to customers and administrative costs to the agency without any measurable benefit is unconscionable and should be rejected outright.

## VI. RATE BASE

### Plant

Q. HAVE YOU REVIEWED THE COMPANY'S REQUEST FOR CAPITAL ADDITIONS FOR 2008 AND 2009?

A. Yes. The Company has proposed a stepped up capital program for 2008 and 2009. Over the past five years the Company has averaged $44,784,558 in capital expenditures. The actual expenditures during this time period were on average approximately 97% of budgeted. For 2008 and 2009, the Company is proposing to expend $62 million and $60 million, respectively. That represents an increase of approximately 33.3% over the 2003-2007 five year average. I believe that this is a significant increase in plant that should be closely monitored.

Q. WHAT CONCERNS DO YOU HAVE WITH THE COMPANY'S REQUEST IN PROJECTED PLANT ADDITIONS?

A. First, the Company's witness Bruce Narzissenfeld states that a significant portion of the cost is associated with the construction of revenue producing facilities to serve new customers or to accommodate increased use by existing customers. As discussed below, the Company's projected growth assumptions are inconsistent with this theory. Second, I believe that the Company has overrstated the projected cost for new pipe.

Q. WHY IS THERE A CONCERN WITH MR. NARZISSENFELD'S STATEMENT REGARDING THE ADDITION OF NEW CUSTOMERS AND THE INCREASED USE BY EXISTING CUSTOMERS?

A. The explanation for the increase in plant cost being driven by an increase in customers and an increase in existing customer's usage is in direct contradiction to the Company's other testimony and what is reflected in the filing. In reviewing the Company's response to OPC Interrogatory No. 78, the actual average customer growth was 5.3% for 2004, 3.6% for 2005, 3.3% for 2006 and .9% for 2007. The response also provided the projected customers for 2008 and 2009 and that indicated an average customer growth of .94% and .38%, for 2008 and 2009, respectively. The filing reflects a similar low growth in customers as the 2008 and 2009 projections provided in the response. The 33% increase in average plant additions is not justified by the Company's projected corresponding increase in the number of customers in the filing. Accordingly, I have a concern that the revenues that result from the new customers do not match the Company's growth in plant for those future customers.

Further, according to Company witness Susan Richards, the average use per customer has declined. This is also in direct contradiction with Mr. Narzissenfeld's argument that the increase in plant is attributable, in part, to accommodating increased use by existing customers.

Q. WHAT IS THE PROBLEM WITH THE COMPANYS CALCULATED COST FOR NEW PIPE?

A. Company witness, William Cantrell, testified that the cost of steel pipe generally used by Peoples has more than doubled and the cost of plastic pipe has increased by more than 45%. OPC requested that the Company provide historical information to confirm Mr. Cantrell's statements. As shown on Citizen's Exhibit HWS-1, Schedule B-3, Page 3, the cost per foot for both steel pipe and plastic pipe used for mains and services has fluctuated from year to year. The cost per foot did increase in 2007 for some pipe, especially for plastic mains but in 2008 the cost per foot declined significantly for the plastic mains.

Q. WHAT DID YOU CONCLUDE FROM THE INFORMATION SUPPLIED BY THE COMPANY?

A. The projected cost per foot for both steel and plastic mains is overstated in the Company's projections and the projected cost per foot of plastic service pipe is understated. Accordingly, I believe that an adjustment is required for the projected costs for mains and for plastic service pipe project costs. The projected cost per foot for steel service pipe is also overstated but because the cost differential for the amount of steel pipe to be installed is minimal, no adjustment is recommended.

Q. WHAT IS YOUR COST RECOMMENDATION BASED ON?

A. The Company's projected cost for steel mains, plastic mains and for plastic service pipe should be adjusted based on the actual 2008 average costs per foot.

Q. IS IT POSSIBLE THAT THE AVERAGE ACTUAL COST PER FOOT IN 2008 IS DIFFERENT BECAUSE OF A CHANGE IN THE PIPE SIZE INSTALLED?

A. No. The Company's projection for 2008 assumed that 74% of the plastic pipe for mains to be installed in 2008 would be 2 inch pipe at an average cost of $16.97 per foot. The 2008 year to date information supplied in response to OPC Interrogatory No. 70 indicated that 80% of the mains installed have been 2 inch plastic pipe at an average cost per foot of $8.12. The majority of the pipe in the projection for plastic pipe was 2 inch and the majority installed to date has been 2 inch pipe. The difference is the Company's projected cost per foot of $16.97 is more than double the actual cost per foot of $8.12. This is a difference of $8.85 per foot.

The Company's projection for 2008 assumed that 45% of the steel pipe for mains to be installed in 2008 would be greater than 10 inches at an average cost of $86.46 per foot. In the response to OPC Interrogatory No. 70, Peoples indicated that 31% of the steel mains installed in 2008, were pipe sized greater than 10 inches and that they cost an average of $49.13 per foot. The major projected cost contributor for steel mains in 2008 has been pipe greater than 10 inches. Similarly, the actual 2008 year to date steel pipe with the greatest amount of pipe installed and the most cost to date has been pipe that is greater than 10 inches. The projections and actual to date installation costs for steel pipe are both driven by pipe that is greater than 10 inches. Again, the significant difference is the projected cost per foot. The Company's projected cost of $86.46 per foot exceeds the actual cost per foot of $49.13 by $37.33 per foot.

Q. HOW SIGNIFICANT IS THE DIFFERENCE IN THE OVERALL COST PER FOOT?

A. As shown on Citizen's Exhibit HWS-1, Schedule B-3, Page 3, the Company used the 2007 average cost per foot of $19.30 for plastic mains for both 2008 and 2009. The actual overall average cost per foot for plastic mains in 2008 was $9.75. For steel mains, the Company reflected an overall average cost per foot of $53.59 and $38.35 for 2008 and 2009, respectively. The actual overall average cost per foot for 2008 to date was $40.77. As shown on lines 10 and 11 of Citizen's Exhibit HWS-1, Schedule B-3, Page 3, the differences between the Company's projected cost for mains and Citizen's projected cost using actual 2008 costs is significant. The 2008 costs to date refute the Company's claim that the cost per foot has materially increased. Therefore, no increase in the projected price per foot above the actual 2008 levels should be allowed. The sum of the differences for 2008 and 2009 is an overstatement of projected project costs for mains of $13,277,817 and $10,969,224, respectively.

The difference for service pipe is not as significant as the difference for mains, but the understatement of cost for plastic service pipe is enough that an adjustment should be made. As shown on lines 21 and 22 of Citizen's Exhibit HWS-1, Schedule B-3, Page 3, the projected costs for plastic service lines are understated in 2008 and 2009 by $1,665,266 and $2,056, 879, respectively.

Q. WHAT ADJUSTMENT SHOULD BE MADE TO THE AVERAGE RATE BASE FOR MAINS AND SERVICES IN THE PROJECTED TEST YEAR?

A. The Company's average projected plant should be reduced $2,356,919 for the steel mains and $15,833,458 for plastic mains. The average projected plant cost for plastic service pipe should be increased $2,912,691. The calculations of the respective adjustments are shown on Citizen's Exhibit HWS-1, Schedule B-3.

Q. WHAT OTHER COSTS IN THE FILING ARE IMPACTED BY THE ADJUSTMENT TO PLANT?

A. As shown on Citizen's Exhibit HWS-1, Schedule B-4, the average balance in accumulated depreciation should be reduced by $369,404. In addition, depreciation expense should be reduced $404,900. The calculation of the reduction in depreciation expense is shown on Citizen's Exhibit HWS-1, Schedule C-9.

## VII. REVENUES

### OFF-SYSTEM SALES

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSAL FOR TREATMENT OF OFF-SYSTEM SALES?

A. Yes. The Company is proposing that off-system sales continue to be shared as they have in the past with the sharing to continue based on any sales in excess of $500,000.

Q. IS THAT AN ACCEPTABLE PROPOSAL?

A. No. There is no reason to assume that the Company will not earn in excess of the $500,000 revenue base currently used as the trigger mechanism for sharing. As shown on Citizen's Exhibit HWS-1, Schedule C-3, the Company has averaged $2,258,556 a year from 2003 through 2007. The 2008, actual to date, if annualized, would be $2,170,781. The bar needs to be raised based on the historical evidence. The sharing should continue but now it should be on revenues in excess of $2,000,000. The Company needs to have an incentive to earn a share of the off-system sales and by raising the bar that incentive will be there. Off-system sales should be increased $1,500,000.

Q. WHO BENEFITS FROM THE COMPANY'S PROPOSAL TO LEAVE THE SHARING FORMULA UNCHANGED?

A. The Company's shareholders receive the benefit. The lower the trigger point the earlier the revenue sharing takes place and that is beneficial to shareholders.

## VIII. OPERATING EXPENSES

### Payroll

Q. WHAT IS THE COMPANY REQUESTING FOR COMPENSATION EXPENSE?

A. The Company has reflected what appears to be at least $23,996,084 of base compensation, overtime and other compensation. In addition, the Company is requesting $2,714,000 of incentive compensation. The amounts requested are not fully justified and adjustments are required.

Q. WHY DID YOU INDICATE THAT THE COMPANY HAS REQUESTED AT LEAST $23,996,084?

A. The filing on Company Schedule G-2, Page 19, identifies $23,632,084 of payroll expense. The testimony of Mr. Higgins along with the responses to OPC Interrogatories Nos. 37 and 82 indicate that the $364,000 of "Other not trended" costs in Account 871 is for 4 additional gas control analysts. That results in a total compensation expense of $23,996,084 ($23,632,084 + 364,000). That total is $697,861 different from an adjusted $24,693,945 of 2009 O&M expense identified in the response to OPC Interrogatory No. 61.

Q. WHY HAVE YOU COMPARED THE FILING AMOUNT TO AN ADJUSTED AMOUNT IN THE RESPONSE TO OPC INTERROGATORY NO. 61?

A. The amount for 2009 projected payroll expense on the Company's Schedule G-2 in the filing and the response to OPC Interrogatory No. 61 are not comparable. In the filing, the Company has separated general payroll expense and incentive compensation. In addition, the Company has at least two separate adjustments for payroll in the filing. The first adjustment removes $307,867 of customer service compensation and is identified on Company Schedule G-2. The second adjustment, that was not described in testimony or specifically identified within the filing schedules as payroll, is the $364,000 for the 4 additional gas control analysts.

The response to OPC Interrogatory No. 61 indicates that the total O&M payroll expense for 2009 is $27,716,212. The response also indicates that included in the $27,716,212 is $2,714,400 of incentive compensation. To be comparable to the filing, the $2,714,400 for incentive compensation and the $307,867 of customer service compensation must be removed from the $27,716,212 of total payroll expense identified in OPC Interrogatory No. 61 resulting in the adjusted $24,693,945.

Q. WHY IS THE COMPARABILITY A PROBLEM?

A. In analyzing the response to OPC Interrogatory No. 61, I performed a calculation for the 2007 base year in an attempt to verify the validity of the response. The base year expense in the response could be reconciled to the Company Schedule G-2 in the filing. Because the base year could be reconciled to OPC Interrogatory No. 61, the response is presumed accurate. However, the 2009 projected year payroll expense in OPC Interrogatory No. 61could not be reconciled to the projected salary expense for the test year in the MFRs, there is a concern that the 2009 test year may have another $697,861 of payroll expense that has not been identified and we have not been able to locate. Adding to that concern is the fact that there is no testimony which provides a description or justification for the additional $697,861 if it does in fact exist.

Q. WHAT IS THE PROBLEM WITH THE GENERAL COMPENSATION EXPENSE INCLUDED IN THE FILING?

A. The Company has trended the payroll for some accounts using a combined trending for payroll and customer growth. However, the customer growth reflected in the filing does not warrant additional personnel. As discussed earlier, the Company is projecting less than 1%

customer growth in the 2009 test year. On Citizen's Exhibit HWS-1, Schedule C-4, an adjustment of $210,199 has been calculated to remove the excess compensation associated with customer growth.

Q. WHAT DO YOU RECOMMEND FOR THE UNEXPLAINED $697,861 DIFFERENCE?

A. If the $697,861 is in fact included in the filing, it also should be removed because the Company has not provided any justification in the filing for it to be allowed. At the very least the Company should be required to reconcile the O&M expense within the response to OPC Interrogatory No. 61 to the filing.

<u>Incentive Compensation</u>

Q. WHY ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S REQUEST FOR INCENTIVE COMPENSATION?

A. The Company's inclusion of incentive compensation in O&M expense has not been justified. Incentive compensation is to be paid based on performance. The performance is to achieve or exceed target goals. The Company failed to provide sufficient information to totally evaluate the goals that are being relied on and has failed to show that the goals that are set are realistic. Further, there are no assurances that the Company will achieve the target goals that the Company has based its claim for incentive compensation in rates. The Company has failed to prove that there is a benefit to ratepayers that would justify payment of incentive compensation by ratepayers.

Q. WAS THE INFORMATION PROVIDED IN RESPONSE TO DISCOVERY SUFFICIENT TO EVALUATE THE INCENTIVE COMPENSATION PLAN GOALS?

A. No. The Company was requested in OPC Interrogatory No. 42 to provide for each of the years 2003-2007, the respective company and team goals and the respective actual results for each of the goals. The desired response provided summaries for 2003-2007 but the information was not complete. For example, the 2003 and 2004 information identified customer goals and some financial goals but the summaries made reference to other documentation that was not provided. Next, the summaries for 2005-2007 identified financial goals and results, but no information on customer service and reliability goals were identified and/or provided.

Q. WHY DO YOU CONTEND THAT THE COMPANY HAS FAILED TO SHOW THAT THE GOALS SET ARE REALISTIC GOALS?

A. While the information supplied was less than sufficient, the response did provide information to show that the 2004 customer service goals were adjusted to make them easier to achieve than the 2003 goals. I also noted that the financial goals for 2005-2007, which are more shareholder related, lack continuity and did not appear to be comparable from year to year.

Q. IS IT POSSIBLE THAT THE GOALS IDENTIFIED ARE ALL THE GOALS THAT EXISTED IN EACH OF THE RESPECTIVE YEARS?

A. No, it is evident that the Company failed to supply all the information that was available with respect to the goals and the achievement of the goals. In response to OPC POD No. 35, the Company provided additional incentive compensation information, more specifically a document for each of the years 2005-2008 that identified the various goals. Customer and safety goals were identified in each of the years. Missing from the response to OPC Interrogatory No. 42 is information as to what the results were in those years specific to the customer service and safety goals.

Q. WHAT IS THE BASIS FOR YOUR STATEMENT THAT THERE IS NO ASSURANCE THAT THE COMPANY WILL ACHIEVE THE TARGET GOALS?

A. The response to OPC Interrogatory No. 41 lists the target amount for incentive compensation and the actual expense for incentive compensation for each of the years 2003-2007. In three of the five years listed the Company failed to pay out the target amount. The remaining two years, 2005 and 2006, suggest that the Company performed at an exemplary level based on the significant payout that occurred.

Q. IS IT POSSIBLE TO DETERMINE WHETHER THE GOALS ARE BENEFICIAL TO CUSTOMERS?

A. No. Since the Company provided insufficient discovery responses to OPC's requests for information, it is not possible to determine whether the goals that apparently were achieved were goals that required a high level of performance that would justify payment of the incentive compensation. There is not sufficient information in the record to evaluate the reasonableness of the Company goals and/or determine whether the goals are set in a manner and at a level that would truly provide an incentive to perform and to provide any benefit to ratepayers. Thus, the cost for incentive compensation is not justified.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING FOR THE UNJUSTIFIED INCENTIVE COMPENSATION?

A. The incentive compensation request for $2,714,000 should be denied in its entirety.

<u>Employee Benefits</u>

Q. IS THERE A PROBLEM WITH THE COMPANY'S REQUESTED EMPLOYEE BENEFIT EXPENSE?

A. Yes. The Company has included an excessive amount of unjustified costs in the benefit described as Employee Welfare/Activity and the Company's benefits expense includes the excessive compensation perks of Restricted Stock Grants and Stock Options.

Q. WHY ARE COSTS INCLUDED IN THE EMPLOYEE WELFARE/ACTIVITY BENEFIT CONSIDERED EXCESSIVE AND UNJUSTIFIED?

A. The Company's total cost in the 2007 base year for this expense category was $211,374. In response to OPC Interrogatory No. 13, the Company identified certain expenses that totaled to $122,720 that were to be removed as part of the ratemaking process from the base year. In the filing the Company removed $122,700 from the projected test year 2009 projected expense of $390,400. The problem is the Company increased the expense for Employee Welfare/Activity using inflation factors but did not make a similar change to the amount to be adjusted from expense. The base test year costs were trended and the adjustment to the base test year should have been adjusted accordingly. The Company then added another $164,500 of costs without sufficiently explaining and/or justifying the increase.

Q. WHAT ARE THE COSTS INCLUDED IN THE ADDITIONAL $164,500?

A. The costs are $27,000 for wellness, $10,000 for interviews, $90,000 for crucial conversations and $37,500 for job postings. The costs are additional unjustified costs added to increase the operating expenses.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING FOR EMPLOYEE WELFARE/ACTIVITY EXPENSE?

A. The Company's projected 2009 expense for Employee Welfare/Activity cost should be reduced $172,881. The calculation is shown on Citizen's Exhibit HWS-1, Schedule C-5. The adjustment removes the $122,720 identified by the Company plus the $8,361 of inflation added in the filing and the $164,500 of unjustified new costs.

Q. WHAT IS THE PROBLEM WITH THE COMPANY INCLUDING RESTRICTED STOCK GRANTS AND STOCK OPTIONS IN THE PROJECTED TEST YEAR 2009?

A. The cost associated with restricted stock grants and stock options are considered excessive compensation that should not be paid for with ratepayer funds. Select individuals of the Company are highly compensated in the form of base pay, incentives and various other benefits. The addition of restricted stock grants and stock options only increases the disparity between the general employee population and the executive levels. The cost of this perk is especially excessive given the current economy and taking into consideration the fact that very few of the Company ratepayers have a similar benefit available to them.

The Company's benefit expense should be reduced by the $569,500 of costs for this excessive perk.

Pipeline Integrity Expense

Q. WHY IS THE COMPANY REQUESTING AN INCREASE IN EXPENSE FOR PIPELINE INTEGRITY?

A. Mr. Higgins states that a new rule is expected to be adopted, that will require a significantly larger level of expense in 2009. The rule as outlined by Mr. Higgins identifies various steps that are to be complied with. It is important to note that the steps enumerated on page 35 of Mr. Higgins' testimony are steps that a prudently operated distribution company should already have had in existence. The only exception to the procedures identified by Mr. Higgins is the Excess Flow Valve (EFV) installation in all new or replaced service lines after June 1, 2008. To meet the anticipated requirements, the Company has estimated that the 2009 projected test year expense in Account 887 should be increased by $501,930. This increase is not justified.

Q. WOULD YOU EXPLAIN WHY THE INCREASE IS NOT JUSTIFIED?

A. Both Mr. Higgins and Mr. Binswanger state that the estimated costs for the pipeline integrity work are not known. The 2009 projected test year includes a total of $751,500 of costs for the pipeline integrity program and of that estimated cost, approximately $100,000 is recurring. The new, nonrecurring costs for the 2009 pipeline integrity program are an estimated $400,000 for casing indirect assessments and an estimated $250,000 for plan development, documentation and risk assessment. The estimated $650,000 of costs is not expected to be expended in 2010 and beyond. In fact, according to Company exhibit (JPH-4) the cost for each year 2010 through 2013 is estimated to be approximately $550,000. Only in the 2009 projected test year does the estimated cost exceed the approximate $550,000 anticipated in either 2008 or 2010 through 2013. Moreover, prior to the 2007 base year the Company expended a total of $78,800 over the three year period 2004 through 2006. As of July 2008, the Company had only expended $34,000 of the $500,000 estimated for 2008. History does not support the Company's estimate. Additionally, the Company's witness has stated that Peoples cannot predict the associated future expenses of this program. Due to the unknown nature of these costs they should not be allowed at the level requested.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING?

A. The Company's request should be reduced by $250,000. An adjustment of $250,000 reduces the Company's unknown cost estimate to $501,500, which is similar to the 2008 amount and slightly below the estimated costs for each of the years 2010 through 2013. Further, the $501,500 that I have recommended for the 2009 projected pipeline integrity program is $251,930 more than the 2007 base year cost of $249,570, an increase of 100%.

Directors and Officers Liability Insurance

Q. WHY ARE YOU RECOMMENDING AN ADJUSTMENT FOR DIRECTORS AND OFFICERS LIABILITY INSURANCE?

A. Directors and Officers Liability Insurance (DOL) is insurance that protects not only directors and officers when bad and/or questionable decisions are made but it ultimately protects shareholders. Therefore, shareholders should be responsible for the cost of DOL insurance.

Q. HOW ARE SHAREHOLDERS ULTIMATELY PROTECTED BY THE DOL INSURANCE?

A. Shareholders appoint directors and the directors decide on who should be officers of the Company. If litigation occurs because of decisions made by directors and/or officers, the insurance provides coverage for the directors and/or officers from the claims made. That insurance not only protects the directors and/or officers but it protects the shareholders who were responsible for placing the directors and officers in the position of authority. The irony of this is that in most cases the claim is made by shareholders. It is important to note that ratepayers have no say in the appointment or hiring of directors and officers, respectively and ratepayers do not receive any benefit from any litigation.

Q. HOW DO YOU RESPOND TO A CONTENTION THAT DOL INSURANCE IS REQUIRED TO ATTRACT AND/OR RETAIN QUALIFIED EXECUTIVES?

A. That argument is not justification for the cost to be included in rates. Commissions exclude portions of executive salaries, incentive compensation and other perks that may be offered to officers and directors and the cost of DOL insurance is no different. Officers and directors are compensated for their time and usually the compensation includes generous benefit packages that are considered sufficient. Ratepayers pay for a large portion of that compensation, if not all, and should not be required to pay for the cost of insurance that provides no benefit and/or protection to them especially when they do not have a real choice in their service provider.

Q. WHAT ADJUSTMENT ARE YOU RECOMMENDING TO THE COMPANY'S REQUEST FOR DOL INSURANCE IN THE 2009 PROJECTED TEST YEAR?

A. The entire $342,000 requested should be excluded from rates.

Q. WHAT IF THE COMMISSION DECIDES THAT SOME OF THE INSURANCE IS JUSTIFIED AND SHOULD BE ALLOWED?

A. If the Commission finds that there is some justification for ratepayers to share in the cost of DOL insurance then the cost should be limited to the 2003 expense of $167,955. This recommendation takes into consideration the fact that DOL insurance costs have skyrocketed since the accounting scandals that occurred in 2001 and 2002. After 2002, the cost of insurance increased significantly as is the case with the Company. Since 2003 the cost has more than doubled from $167,955 to $386,684 in the 2007 base year. However, absent a showing that DOL insurance, in fact, does benefit ratepayers the escalation in costs due to general corporate misdeeds should not be borne by them.

<u>Storm Damage Reserve</u>

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSAL TO ESTABLISH A RESERVE FOR STORM DAMAGE?

A. Yes. The Company is requesting that an accrual of $100,000 annually be allowed in rates to establish an unfunded storm damage reserve of $1,000,000. This request is not appropriate for two reasons. First, the Company assumes that it will incur unusual and unpredictable costs in the future from storms even though there is no evidence that a significant level of storm costs will incur and produce damage. Second, the Company is requesting that the reserve be unfunded. This request is not appropriate because ratepayers would be providing the funds for such a reserve, and without a funding requirement, the Company would be allowed to expend the cost-free funds for any purpose desired.

Q. WHAT IS THE BASIS OF THE COMPANY'S REQUESTED ACCRUAL?

A. The Company reviewed the storm costs for the last ten years and determined that on average the Company incurred $69,454 of storm expense excluding straight time payroll. Over a five-year period the average cost for storm expense excluding straight time payroll was $133,463. The Company assumed that averaging the two averages would result in a reasonable level of expense to accrue on an annual basis.

Q. WHAT IS THE PROBLEM WITH THE COMPANY'S REQUEST?

A. The Company has assumed that a significant storm will occur, that a reserve would provide for rate stability from a customer perspective and a reserve will provide greater financial stability for the Company. The problem is that in only two years of the last ten years did the Company incur any abnormal level of costs from storms. In 2004 and 2005, the Company expensed $603,353 and $200,230, respectively. Furthermore, the amounts expensed included base payroll by admission of the Company and according to the Company's work papers it also included bonus and overtime payroll. Interestingly, the Company only made an adjustment for base payroll of approximately $200,000 when calculating the respective averages.

An argument may be made by the Company that because of the circumstances the overtime would be appropriately included in the calculation. However, based on my review of the historical overtime as provided in response to OPC Interrogatory No. 31, that argument has no merit. The overtime in 2004 and 2005 (the storm years) was less than the overtime in 2006 and 2007 (non-storm years). As a result, there was no significant increase in overtime attributable to storms. Therefore, there is no justification for including the overtime dollars in the calculation of the averages. The 2004 and 2005 expense, without adjusting for overtime, is not significant when considering the Company's total requested O&M expense of $135,961,429. There is no need or justification for establishing a reserve of $1 million for storm damage. The Company's request for $100,000 annually should be denied.

<u>Rate Case Expense</u>

Q. WHAT IS THE COMPANY REQUESTING FOR RATE CASE EXPENSE FOR THIS CASE?

A. The Company has projected a total expenditure of $750,000 to be amortized over a three year period at a cost to ratepayers of $250,000 per year. The estimate consists of $427,500 of consulting fees, $250,000 of legal costs, and $72,500 of other costs. In Docket No. 020384-GU, the Company requested $50,000 for outside consulting costs, $140,000 for legal costs and $50,000 for other expenses. Using the average CPI index on Company Schedule C-37 and the inflation rates proposed by the Company on MFR Schedule G-2, Page 19, the benchmark costs for rate case expense should have increased by only 18.4%, not the 212.5% as requested by the Company. The Company's projected cost is excessive and not appropriate.

Q. WHAT IS THE REASON FOR SIGNIFICANT INCREASE IN THE COMPANY'S REQUEST FOR RATE CASE EXPENSE?

A. According to the response to OPC Interrogatory No. 88, despite the fact that this rate case is essentially the same as the 2002 case, the Company stated that its accounting staff was not capable of handling the additional workload associated with a rate proceeding. Therefore, the Company hired seven different consultants to handle the case for them. In addition to the significant increase attributed to hiring outside consultants to do what is typically predominately done in house, the legal fees increased 78.6%.

Q. IS THERE A PROBLEM WITH THE COMPANY'S REQUEST OTHER THAN THE FACT THAT THE INCREASE IS CONSIDERED EXCESSIVE?

A. Yes. The Company has included amounts that are not supported by the contract information provided in response to OPC POD No. 65. In addition, the three year amortization period requested is not reasonable given the Company's rate case history.

Q. WHAT AMOUNTS INCLUDED IN THE REQUEST ARE DIFFERENT FROM THE CONTRACT INFORMATION SUPPLIED IN RESPONSE TO OPC POD NO. 65?

A. The amount in the filing for C.H. Guernsey is $3,000 less than what is reflected in the contract. The AUS Consultant amount is $6,500 higher than what is in the contract. The Huron Consulting amount is $37,000 more than what is in the contract. In addition, the contract for C. Holden is an "as required" contract with a fixed hourly rate without any cap.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COST PROJECTED BY THE COMPANY?

A. Yes. The costs should reflect the contract amounts supplied by the Company in response to OPC POD No. 65. In addition, the $50,000 of costs estimated for C. Holden should be reduced by 50% to $25,000 because the Company should have been handling more of the rate case internally. There is no justification for $50,000 when the contract is "as required." The total cost adjustment recommended is a reduction of only $65,500, despite the fact that the costs for Huron Consulting and AUS Consultants are not justified. These costs should have been avoided by the Company performing the tasks that are typically done by the Company. Also of concern is the $7,500 and $10,000 of costs for Black & Veatch and F. Sivard, respectively. No detail was provided for the respective amounts in the response, only an indication that the money had been expended and that some planning and review was performed. Once again, these tasks already performed are tasks that should have been performed internally.

Q. WHY IS THE THREE YEAR AMORTIZATION PERIOD A PROBLEM?

A. The Company's last rate case was in 2002. The use of a three-year amortization period is not supported by the Company's recent history of five years between rate cases. The use of a five year amortization period is more appropriate and is recommended.

Q. WHAT ADJUSTMENT TO THE COMPANY'S REQUEST IS REQUIRED?

A. As shown on Citizen's Exhibit HWS-1, Schedule C-6, the Company's amortization expense should be reduced $113,100. In addition, the Company's unamortized balance in rate base should be reduced $8,950, increasing the negative working capital allowance $8,950.

Marketing Expense

Q. IS THERE A PROBLEM WITH THE COMPANY'S REQUEST FOR MARKETING EXPENSE?

A. Yes. Mr. Higgins, in his pre-filed testimony, attributes the increase in Account 912 to a new contract with an affiliate TECO Partners, Inc. (TPI). The contract that is effective January 1, 2008 provides for new or expanded services. The contract was provided in response to OPC POD No. 51 and consists of a fixed amount and a set prepaid but variable amount escalated annually by the CPI. The cost of this contract is questionable, especially with respect to the variable portion of the contract.

Q. WHAT IS THE CONCERN WITH THE VARIABLE PORTION OF THE CONTRACT?

A. The variable portion provides for a payment of $2.6 million prorated monthly. At the end of the year, the variable amount is adjusted up or down depending on whether the number of "New Signings" is greater than or less than a target level. For 2009, the target level is to add 12,000 "New Signings." The increase in the number of customers reflected in the filing was only 593 customers based on a year-end count or 1,298 customers based on an average basis for the year. Based on the requested level of projected customer growth, there is not justification for compensating TPI for an unachieved 2009 gross increase in new customer signings. It is also of added concern that from all appearances, the affiliate, TPI, is compensated based on gross additions and not net. In other words, TPI will be compensated for maintaining the status quo or even if there is a decline in customers as long as during the year they sign 1,200 customers. A variable component should be cost justified and there is no evidence that the amount reflected in the filing is justified.

Q. WHAT ADJUSTMENT TO MARKETING EXPENSE ARE YOU RECOMMENDING?

A. As shown on Citizen's Exhibit HWS-1, Schedule C-7, the marketing expense should be reduced $2,000,530, from the net variable expense of $2,144,100 reflected in the filing less the assumed $143,570 earned for the average net addition of 1,298 customers in 2009.

<u>TECO Energy Allocated Costs</u>

Q. IS THERE A PROBLEM WITH COSTS ALLOCATED BY TECO ENERGY TO PEOPLES GAS SYSTEM?

A. Yes. In 2007, Account 921 included $6,722,093 of charges from Tampa Electric and $4,671,927 of charges from TECO Energy. Based on the response to OPC POD No. 47 included in the allocated costs from TECO Energy are costs for the incentive compensation plan, there are costs for restricted stock grants and stock options and there are costs for DOL insurance. All three costs are the same as unjustified costs expensed by Peoples, as discussed earlier and recommended for removal. Therefore, consistent with the recommendations made earlier regarding each of the respective Peoples expenditures the TECO Energy allocated costs totaling an estimated $1,261,437 should also be removed.

Q. HOW DID YOU DETERMINE THE ADJUSTMENT THAT IS BEING RECOMMENDED?

A. The Company response to OPC POD No. 47 indicated that $3,990,000 of costs was being allocated to Peoples from TECO Energy in the 2009 projected test year. As shown on Citizen's Exhibit HWS-1, Schedule C-8, a ratio of 89.75% was developed based on the actual 2007 cost of $4,445,825 and the projected 2009 cost of $3,990,000. That ratio was applied to the total actual 2007 costs of $1,405,546 for incentive compensation, restricted stock grants/options and DOL insurance. The result is an estimated 2009 projected test year expense of $1,261,437.

<u>Interest Synchronization Adjustment</u>

Q. WHY ARE YOU MAKING AN ADJUSTMENT FOR INTEREST SYNCHRONIZATION?

A. The OPC has recommended certain adjustments to rate base and changes to the capital structure that impact the amount of interest that is deductible in the income tax calculation. The flow through impact of those changes are shown on Citizen's Exhibit HWS-1, Schedule C-10, increase income tax expense $189,748.

<u>Income Taxes</u>

Q. WILL THE OPC'S RECOMMENDED ADJUSTMENTS TO OPERATING INCOME AND EXPENSES IMPACT INCOME TAXES?

A. Yes. The impact of the OPC's recommended adjustments are calculated on Citizen's Exhibit HWS-1, Schedule C-11. The calculation reflects the effective state and federal income tax rate of 38.575%.

IX <u>PARENT DEBT ADJUSTMENT</u>

Q. WHAT IS THE CONCERN WITH THE PARENT DEBT ADJUSTMENT?

A. My concern is that the Company did not make an adjustment to take into consideration the fact that the Parent Company may have financed some of the equity in Peoples. Company witness Gillette states that a parent company debt adjustment is inappropriate since the $400 million of existing parent debt was raised on behalf of a non-regulated affiliate and was not used to fund any equity infusions to Peoples. The statement alone without a detailed analysis to show how all parent debt was specifically used is not sufficient to show that the parent debt benefit was not filtered down to Peoples. Rule 25-14-004(3) states that ..."It shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure." Thus, it is the Company's burden to make this showing and a statement alone is not sufficient. This is an issue in the Tampa Electric, Docket No. 080317-EI, proceeding and any decision by the Commission in that proceeding should be appropriately applied to this proceeding.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does for now. However, pending a review of responses to discovery still outstanding additional adjustments may be required.

# APPENDIX 1

# QUALIFICTIONS OF HELMUTH W. SCHULTZ, III

# APPENDIX I
## QUALIFICATIONS OF HELMUTH W. SCHULTZ, III

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

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

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

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

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

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| U-5331 | Consumers Power Co.<br>Michigan Public Service Commission |

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| Docket No. 770491-TP | Winter Park Telephone Co.<br>Florida Public Service Commission |
| Case Nos. U-5125<br>and U-5125(R) | Michigan Bell Telephone Co.<br>Michigan Public Service Commission |
| Case No. 77-554-EL-AIR | Ohio Edison Company<br>Public Utility Commission of Ohio |
| Case No. 79-231-EL-FAC | Cleveland Electric Illuminating<br>Public Utility Commission of Ohio |
| Case No. U-6794 | Michigan Consolidated Gas Refunds<br>Michigan Public Service Commission |
| Docket No. 820294-TP | Southern Bell Telephone and Telegraph Co.<br>Florida Public Service Commission |
| Case No. 8738 | Columbia Gas of Kentucky, Inc.<br>Kentucky Public Service Commission |
| 82-165-EL-EFC | Toledo Edison Company<br>Public Utility Commission of Ohio |
| Case No. 82-168-EL-EFC | Cleveland Electric Illuminating Company,<br>Public Utility Commission of Ohio |
| Case No. U-6794 | Michigan Consolidated Gas Company Phase II,<br>Michigan Public Service Commission |
| Docket No. 830012-EU | Tampa Electric Company,<br>Florida Public Service Commission |
| Case No. ER-83-206 | Arkansas Power & Light Company,<br>Missouri Public Service Commission |
| Case No. U-4758 | The Detroit Edison Company - (Refunds),<br>Michigan Public Service Commission |

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| Case No. 8836 | Kentucky American Water Company,<br>Kentucky Public Service Commission |
| Case No. 8839 | Western Kentucky Gas Company,<br>Kentucky Public Service Commission |
| Case No. U-7650 | Consumers Power Company - Partial and Immediate<br>Michigan Public Service Commission |
| Case No. U-7650 | Consumers Power Company - Final<br>Michigan Public Service Commission |
| U-4620 | Mississippi Power & Light Company<br>Mississippi Public Service Commission |
| Docket No. R-850021 | Duquesne Light Company<br>Pennsylvania Public Utility Commission |
| Docket No. R-860378 | Duquesne Light Company<br>Pennsylvania Public Utility Commission |
| Docket No. 87-01-03 | Connecticut Natural Gas<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 87-01-02 | Southern New England Telephone<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 3673-U | Georgia Power Company<br>Georgia Public Service Commission |
| Docket No. U-8747 | Anchorage Water and Wastewater Utility<br>Alaska Public Utilities Commission |
| Docket No. 8363 | El Paso Electric Company<br>The Public Utility Commission of Texas |

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| Docket No. 881167-EI | Gulf Power Company<br>Florida Public Service Commission |
| Docket No. R-891364 | Philadelphia Electric Company<br>Pennsylvania Office of the Consumer Advocate |
| Docket No. 89-08-11 | The United Illuminating Company<br>The Office of Consumer Counsel and<br>the Attorney General of the State of Connecticut |
| Docket No. 9165 | El Paso Electric Company<br>The Public Utility Commission of Texas |
| Case No. U-9372 | Consumers Power Company<br>Before the Michigan Public Service Commission |
| Docket No. 891345-EI | Gulf Power Company<br>Florida Public Service Commission |
| ER89110912J | Jersey Central Power & Light Company<br>Board of Public Utilities Commissioners |
| Docket No. 890509-WU | Florida Cities Water Company, Golden Gate Division<br>Florida Public Service Commission |
| Case No. 90-041 | Union Light, Heat and Power Company<br>Kentucky Public Service Commission |
| Docket No. R-901595 | Equitable Gas Company<br>Pennsylvania Consumer Counsel |
| Docket No. 5428 | Green Mountain Power Corporation<br>Vermont Department of Public Service |
| Docket No. 90-10 | Artesian Water Company<br>Delaware Public Service Commission |

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| Docket No. 900329-WS | Southern States Utilities, Inc.<br>Florida Public Service Commission |
| Case No. PUE900034 | Commonwealth Gas Services, Inc.<br>Virginia Public Service Commission |
| Docket No. 90-1037*<br>(DEAA Phase) | Nevada Power Company - Fuel<br>Public Service Commission of Nevada |
| Docket No. 5491** | Central Vermont Public Service Corporation<br>Vermont Department of Public Service |
| Docket No.<br>U-1551-89-102 | Southwest Gas Corporation - Fuel<br>Before the Arizona Corporation Commission |
| | Southwest Gas Corporation - Audit of Gas<br>Procurement Practices and Purchased Gas Costs |
| Docket No.<br>U-1551-90-322 | Southwest Gas Corporation<br>Before the Arizona Corporation Commission |
| Docket No.<br>176-717-U | United Cities Gas Company<br>Kansas Corporation Commission |
| Docket No. 5532 | Green Mountain Power Corporation<br>Vermont Department of Public Service |
| Docket No. 910890-EI | Florida Power Corporation<br>Florida Public Service Commission |
| Docket No. 920324-EI | Tampa Electric Company<br>Florida Public Service Commission |
| Docket No. 92-06-05 | United Illuminating Company<br>The Office of Consumer Counsel and the Attorney<br>General of the State of Connecticut |

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| Docket No. C-913540 | Philadelphia Electric Co.<br>Before the Pennsylvania Public Utility Commission |
| Docket No. 92-47 | The Diamond State Telephone Company<br>Before the Public Service Commission<br>of the State of Delaware |
| Docket No. 92-11-11 | Connecticut Light & Power Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 93-02-04 | Connecticut Natural Gas Corporation<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 93-02-04 | Connecticut Natural Gas Corporation<br>(Supplemental)<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 93-08-06 | SNET America, Inc.<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 93-057-01** | Mountain Fuel Supply Company<br>Before the Public Service Commission of Utah |
| Docket No.<br>94-105-EL-EFC | Dayton Power & Light Company<br>Before the Public Utilities Commission of Ohio |
| Case No. 399-94-297** | Montana-Dakota Utilities<br>Before the North Dakota Public Service<br>Commission |
| Docket No.<br>G008/C-91-942 | Minnegasco<br>Minnesota Department of Public Service |

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| Docket No. R-00932670 | Pennsylvania American Water Company<br>Before the Pennsylvania Public Utility Commission |
| Docket No. 12700 | El Paso Electric Company<br>Public Utility Commission of Texas |
| Case No. 94-E-0334 | Consolidated Edison Company<br>Before the New York Department of Public Service |
| Docket No. 2216 | Narragansett Bay Commission<br>On Behalf of the Division of Public Utilities and Carriers,<br>Before the Rhode Island Public Utilities Commission |
| Docket No. 2216 | Narragansett Bay Commission - Surrebuttal<br>On Behalf of the Division of Public Utilities and Carriers,<br>Before the Rhode Island Public Utilities Commission |
| Case No. PU-314-94-688 | U.S. West Application for Transfer of Local Exchanges<br>Before the North Dakota Public Service Commission |
| Docket No. 95-02-07 | Connecticut Natural Gas Corporation<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 95-03-01 | Southern New England Telephone Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. U-1933-95-317 | Tucson Electric Power<br>Before the Arizona Corporation Commission |

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|---|---|
| Docket No. 5863* | Central Vermont Public Service Corporation<br>Before the Vermont Public Service Board |
| Docket No. 96-01-26** | Bridgeport Hydraulic Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket Nos. 5841/ 5859 | Citizens Utilities Company<br>Before Vermont Public Service Board |
| Docket No. 5983 | Green Mountain Power Corporation<br>Before Vermont Public Service Board |
| Case No. PUE960296** | Virginia Electric and Power Company<br>Before the Commonwealth of Virginia<br>State Corporation Commission |
| Docket No. 97-12-21 | Southern Connecticut Gas Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 97-035-01 | PacifiCorp, dba Utah Power & Light Company<br>Before the Public Service Commission of Utah |
| Docket No.<br>G-03493A-98-0705* | Black Mountain Gas Division of Northern States<br>Power Company, Page Operations<br>Before the Arizona Corporation Commission |
| Docket No. 98-10-07 | United Illuminating Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 99-01-05 | Connecticut Light & Power Company<br>State of Connecticut<br>Department of Public Utility Control |

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|---|---|
| Docket No. 99-04-18 | Southern Connecticut Gas Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 99-09-03 | Connecticut Natural Gas Corporation<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No.<br>980007-0013-003 | Intercoastal Utilities, Inc.<br>St. John County - Florida |
| Docket No. 99-035-10 | PacifiCorp dba Utah Power & Light Company<br>Before the Public Service Commission of Utah |
| Docket No. 6332 ** | Citizens Utilities Company - Vermont Electric Division<br>Before the Vermont Public Service Board |
| Docket No.<br>G-01551A-00-0309 | Southwest Gas Corporation<br>Before the Arizona Corporation Commission |
| Docket No. 6460** | Central Vermont Public Service Corporation<br>Before the Vermont Public Service Board |
| Docket No. 01-035-01* | PacifiCorp dba Utah Power & Light Company<br>Before the Public Service Commission of Utah |
| Docket No. 01-05-19<br>Phase I | Yankee Gas Services Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 010949-EI | Gulf Power Company<br>Before the Florida Office of the Public Counsel |
| Docket No.<br>2001-0007-0023 | Intercoastal Utilities, Inc.<br>St. Johns County - Florida |

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|---|---|
| Docket No. 6596 | Citizens Utilities Company - Vermont Electric Division<br>Before the Vermont Public Service Board |
| Docket Nos. R. 01-09-001<br>I. 01-09-002 | Verizon California Incorporated<br>Before the California Public Utilities Commission |
| Docket No. 99-02-05 | Connecticut Light & Power Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 99-03-04 | United Illuminating Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 5841/5859 | Citizens Utilities Company<br>Before the Vermont Public Service Board |
| Docket No. 6120/6460 | Central Vermont Public Service Corporation<br>Before the Vermont Public Service Board |
| Docket No. 020384-GU | Tampa Electric Company d/b/a/ Peoples Gas System<br>Before the Florida Public Service Commission |
| Docket No. 03-07-02 | Connecticut Light & Power Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 6914 | Shoreham Telephone Company<br>Before the Vermont Public Service Board |
| Docket No. 04-06-01 | Yankee Gas Services Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket Nos. 6946/6988 | Central Vermont Public Service Corporation<br>Before the Vermont Public Service Board |

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|---|---|
| Docket No. 04-035-42** | PacifiCorp dba Utah Power & Light Company<br>Before the Public Service Commission of Utah |
| Docket No. 050045-EI** | Florida Power & Light Company<br>Before the Florida Public Service Commission |
| Docket No. 050078-EI** | Progress Energy Florida, Inc.<br>Before the Florida Public Service Commission |
| Docket No. 05-03-17 | The Southern Connecticut Gas Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. 05-06-04 | United Illuminating Company<br>State of Connecticut<br>Department of Public Utility Control |
| Docket No. A.05-08-021 | San Gabriel Valley Water Company, Fontana Water Division<br>Before the California Public Utilities Commission |
| Docket NO. 7120 ** | Vermont Electric Cooperative<br>Before the Vermont Public Service Board |
| Docket No. 7191 ** | Central Vermont Public Service Corporation<br>Before the Vermont Public Service Board |
| Docket No. 06-035-21 ** | PacifiCorp<br>Before the Public Service Commission of Utah |
| Docket No. 7160 | Vermont Gas Systems<br>Before the Vermont Public Service Board |
| Docket No. 6850/6853 ** | Vermont Electric Cooperative/Citizens Communications Company<br>Before the Vermont Public Service Board |

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|---|---|
| Docket No. 06-03-04**<br>Phase 1 | Connecticut Natural Gas Corporation<br>Connecticut Department of Public Utility Control |
| Application 06-05-025 | Request for Order Authorizing the Sale by Thames GmbH of up to 100% of the Common Stock of American Water Works Company, Inc., Resulting in Change of Control of California-American Water Company<br>Before the California Public Utilities Commission |
| Docket No. 06-12-02PH01** | Yankee Gas Company<br>State of Connecticut<br>Department of Public Utility Control |
| Case 06-G-1332** | Consolidated Edison Company of New York, Inc.<br>Before the NYS Public Service Commission |
| Case 07-E-0523 | Consolidated Edison Company of New York, Inc.<br>Before the NYS Public Service Commission |
| Docket No. 07-07-01 | Connecticut Light & Power Company<br>Connecticut Department of Public Utility Control |
| Docket No. 07-035-93 | Rocky Mountain Power Company<br>Before the Public Service Commission of Utah |
| Docket No. 07-057-13 | Questar<br>Before the Public Service Commission of Utah |
| Docket No. 08-07-04 | United Illuminating Company<br>Connecticut Department of Public Utility Control |

* Certain issues stipulated, portion of testimony withdrawn.

** Case settled.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Docket No. 080318-GU
Exhibit HWS-1
Schedule A-1
Page 1 of 1

Revenue Requirement

| Line No. | Description | Per Company Amount | Maximum Per Citizens Amount | Reference |
|---|---|---|---|---|
| 1 | Adjusted Rate Base | 563,599,434 | 548,682,201 | Schedule B-1 |
| 2 | Required Rate Of Return | 8.88% | 7.77% | Schedule D |
| 3 | Income Requirement | 50,060,255 | 42,647,543 | L.1 x L.2 |
| 4 | Adjusted Net Operating Income | 33,944,697 | 39,195,648 | Schedule C-1 |
| 5 | Income Deficiency (Sufficiency) | 16,115,558 | 3,451,895 | L.3-L.4 |
| 6 | Earned Rate of Return | 6.02% | 7.14% | L.4/L.1 |
| 7 | Gross Revenue Conversion Factor | 1.6436 | 1.6436 | |
| 8 | Revenue Deficiency (Sufficiency) | 26,488,091 | 5,673,535 | L.5 x L.7 |

Source: The Company amounts are from the Exhibit A to the Company Petition.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Adjusted Rate Base

Docket No. 080318-GU
Exhibit HWS-1
Schedule B-1


| Line No. | Description | Per Company Amount | Citizens Adjustments | Per Citizens Amount | Reference |
|---|---|---|---|---|---|
| | Utility Plant | | | | |
| 1 | Intangible Plant | 15,050,317 | | 15,050,317 | |
| 2 | Distribution Plant | 924,899,052 | (15,277,686) | 909,621,366 | B-2 |
| 3 | Construction Work In Progress | 18,249,444 | | 18,249,444 | |
| 4 | Acquisition Adjustment | 2,301,671 | | 2,301,671 | |
| 5 | General Plant | 48,873,806 | | 48,873,806 | |
| 6 | Total | 1,009,374,290 | | 994,096,604 | |
| | Deductions | | | | |
| 7 | Accumulated Depreciation | (426,364,359) | 369,404 | (425,994,955) | B-2 |
| 8 | Customer Adv. For Construction | (7,916,127) | | (7,916,127) | |
| 9 | Net Utility Plant | 575,093,804 | | 560,185,522 | |
| 10 | Working Capital Allownace | (11,494,371) | (8,950) | (11,503,321) | B-2 |
| 11 | Total Rate Base | 563,599,433 | | 548,682,201 | |

Peoples Gas System
Projected Test Year Ended December 31, 2009

Docket No. 080318-GU
Exhibit HWS-1
Schedule B-2
Page 1 of 1

Rate Base Adjustments

| Line No. | Description | Per Citizens Amount | Reference |
|---|---|---|---|
| 1 | Account 376 | (2,356,919) | B-3 |
| 2 | Account 376.02 | (15,833,458) | B-3 |
| 3 | Account 380.02 | 2,912,691 | B-3 |
| 4 | Distribution Plant Adjustment | (15,277,686) | |
| 5 | Working Capital - Rate Case | (8,950) | C-6 |
| 6 | Accumulated Depreciation | (369,404) | B-4 |

Peoples Gas System
Projected Test Year Ended December 31, 2009

Plant Adjustments - Mains/Services



| Line No. | Month | 376 | 376.02 | 380 | 380.02 | Reference |
|---|---|---|---|---|---|---|
| | Per Company | | | | | |
| 1 | Dec-08 | 264,215,368 | 269,476,331 | 37,802,630 | 173,661,112 | a |
| 2 | Jan-09 | 265,014,832 | 272,025,875 | 37,820,139 | 174,442,919 | a |
| 3 | Feb-09 | 265,856,243 | 273,588,539 | 37,837,647 | 175,223,797 | a |
| 4 | Mar-09 | 266,651,505 | 275,850,208 | 37,855,155 | 175,979,306 | a |
| 5 | Apr-09 | 267,656,058 | 278,029,435 | 37,872,664 | 176,794,892 | a |
| 6 | May-09 | 268,505,464 | 279,563,921 | 37,890,172 | 177,599,967 | a |
| 7 | Jun-09 | 269,397,893 | 281,701,152 | 37,907,681 | 178,410,438 | a |
| 8 | Jul-09 | 270,254,835 | 283,205,494 | 37,925,189 | 179,173,042 | a |
| 9 | Aug-09 | 271,133,514 | 284,583,432 | 37,942,697 | 179,960,570 | a |
| 10 | Sep-09 | 271,969,390 | 286,327,741 | 37,960,206 | 180,791,601 | a |
| 11 | Oct-09 | 272,825,378 | 288,505,834 | 37,977,714 | 181,634,574 | a |
| 12 | Nov-09 | 273,539,619 | 290,175,631 | 37,995,222 | 182,425,003 | a |
| 13 | Dec-09 | 274,348,072 | 292,373,432 | 38,012,731 | 183,223,293 | a |
| 14 | Average | 269,336,013 | 281,185,156 | 37,907,681 | 178,409,270 | a |
| | Per Citizens | | | | | |
| 15 | Dec-08 | 264,215,368 | 269,476,331 | 37,802,630 | 173,661,112 | Page 2 |
| 16 | Adjustment | (3,070,892) | (10,206,925) | (98,166) | 1,665,266 | Page 2 |
| 17 | Dec-08 | 261,144,476 | 259,269,406 | 37,704,464 | 175,326,378 | |
| 18 | Jan-09 | 262,059,536 | 260,585,303 | 37,741,123 | 176,314,127 | |
| 19 | Feb-09 | 263,019,185 | 261,402,570 | 37,777,782 | 177,300,756 | |
| 20 | Mar-09 | 263,929,778 | 262,573,016 | 37,814,442 | 178,256,805 | |
| 21 | Apr-09 | 265,062,844 | 263,701,807 | 37,851,101 | 179,285,273 | |
| 22 | May-09 | 266,030,990 | 264,504,837 | 37,887,760 | 180,301,068 | |
| 23 | Jun-09 | 267,044,871 | 265,612,410 | 37,924,419 | 181,323,369 | |
| 24 | Jul-09 | 268,021,030 | 266,400,209 | 37,961,078 | 182,287,971 | |
| 25 | Aug-09 | 269,020,294 | 267,124,142 | 37,997,737 | 183,282,616 | |
| 26 | Sep-09 | 269,974,059 | 268,033,187 | 38,034,397 | 184,329,698 | |
| 27 | Oct-09 | 270,949,202 | 269,161,405 | 38,071,056 | 185,391,177 | |
| 28 | Nov-09 | 271,773,671 | 270,032,802 | 38,107,715 | 186,389,319 | |
| 29 | Dec-09 | 272,698,286 | 271,170,978 | 38,144,374 | 187,396,937 | |
| 30 | Average | 266,979,094 | 265,351,698 | 37,924,419 | 181,321,961 | |
| 31 | Adjustment | (2,356,919) | (15,833,458) | 16,738 | 2,912,691 | L.14-L.30 |

Source: (a) Company Schedule G-1, Page 10.

Rate Base Adjustments

| Line No. | Month | 376 | 376.02 | 380 | 380.02 | Reference |
|---|---|---|---|---|---|---|
| | Per Company | | | | | |
| 1 | Jan-09 | 860,839 | 2,604,402 | 41,533 | 819,432 | a |
| 2 | Feb-09 | 902,786 | 1,617,523 | 41,533 | 818,503 | a |
| 3 | Mar-09 | 856,637 | 2,316,527 | 41,533 | 793,134 | a |
| 4 | Apr-09 | 1,065,928 | 2,234,086 | 41,533 | 853,212 | a |
| 5 | May-09 | 910,780 | 1,589,344 | 41,533 | 842,699 | a |
| 6 | Jun-09 | 953,804 | 2,192,090 | 41,533 | 848,096 | a |
| 7 | Jul-09 | 918,318 | 1,559,200 | 41,533 | 800,229 | a |
| 8 | Aug-09 | 940,054 | 1,432,796 | 41,533 | 825,153 | a |
| 9 | Sep-09 | 897,251 | 1,799,167 | 41,533 | 868,655 | a |
| 10 | Oct-09 | 917,362 | 2,232,951 | 41,533 | 880,598 | a |
| 11 | Nov-09 | 775,616 | 1,724,656 | 41,533 | 828,054 | a |
| 12 | Dec-09 | 869,828 | 2,252,659 | 41,533 | 835,915 | a |
| 13 | | 10,869,203 | 23,555,401 | 498,396 | 10,013,680 | a |
| | Per Citizens | | | | | |
| 14 | Jan-09 | 915,060 | 1,315,897 | 36,659 | 987,749 | |
| 15 | Feb-09 | 959,649 | 817,268 | 36,659 | 986,629 | |
| 16 | Mar-09 | 910,593 | 1,170,445 | 36,659 | 956,049 | |
| 17 | Apr-09 | 1,133,066 | 1,128,791 | 36,659 | 1,028,468 | |
| 18 | May-09 | 968,146 | 803,030 | 36,659 | 1,015,795 | |
| 19 | Jun-09 | 1,013,880 | 1,107,573 | 36,659 | 1,022,301 | |
| 20 | Jul-09 | 976,159 | 787,799 | 36,659 | 964,602 | |
| 21 | Aug-09 | 999,264 | 723,933 | 36,659 | 994,645 | |
| 22 | Sep-09 | 953,765 | 909,045 | 36,659 | 1,047,083 | |
| 23 | Oct-09 | 975,143 | 1,128,218 | 36,659 | 1,061,479 | |
| 24 | Nov-09 | 824,469 | 871,398 | 36,659 | 998,142 | |
| 25 | Dec-09 | 924,615 | 1,138,176 | 36,659 | 1,007,618 | |
| 26 | | 11,553,810 | 11,901,572 | 439,910 | 12,070,559 | Page 3 |
| 27 | Dec-08 | 264,215,368 | 269,476,331 | 37,802,630 | 173,661,112 | b |
| 28 | Adjust.08 | (3,070,892) | (10,206,925) | (98,166) | 1,665,266 | Page 3 |
| 29 | Dec-09 | 272,698,286 | 271,170,979 | 38,144,374 | 187,396,937 | |

Source: (a) Company Schedule G-1, Page 27.
(b) Company Schedule G-1, Page 29.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Pipe Cost Analysis

Docket No. 080318-GU
Exhibit HWS-1
Schedule B-3


| | | Mains | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Line No. | | Cost | Steel Footage | Cost/Foot | Cost | Plastic Footage | Cost/Foot | Reference |
| | Actual | | | | | | | |
| 1 | 2004 | 4,671,233 | 228,248 | 20.47 | 12,383,122 | 1,232,698 | 10.05 | a |
| 2 | 2005 | 3,743,891 | 129,810 | 28.84 | 7,717,508 | 840,705 | 9.18 | a |
| 3 | 2006 | 8,372,633 | 339,866 | 24.64 | 18,048,274 | 2,381,872 | 7.58 | a |
| 4 | 2007 | 3,730,075 | 136,581 | 27.31 | 8,821,029 | 457,118 | 19.30 | a |
| 5 | 2008 | 5,636,984 | 138,266 | 40.77 | 7,816,873 | 801,722 | 9.75 | a |
| | Projected | | | | | | | |
| 6 | 2008 | 12,833,391 | 239,453 | 53.59 | 20,630,825 | 1,069,118 | 19.30 | a |
| 7 | 2009 | 10,869,203 | 283,390 | 38.35 | 23,555,402 | 1,220,674 | 19.30 | a |
| | Citizens Projected | | | | | | | |
| 8 | 2008 | 9,762,499 | 239,453 | 40.77 | 10,423,901 | 1,069,118 | 9.75 | Testimony |
| 9 | 2009 | 11,553,810 | 283,390 | 40.77 | 11,901,572 | 1,220,674 | 9.75 | Testimony |
| | Projected Difference | | | | | | | |
| 10 | 2008 | (3,070,892) | | | (10,206,925) | | | L.8-L.6 |
| 11 | 2009 | 684,607 | | | (11,653,831) | | | L.9-L.7 |

| | | Services | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Cost | Steel Footage | Cost/Foot | Cost | Plastic Footage | Cost/Foot | |
| | Actual | | | | | | | |
| 12 | 2004 | 646,095 | 26,133 | 24.72 | 11,082,740 | 1,265,645 | 8.76 | b |
| 13 | 2005 | 714,541 | 26,961 | 26.50 | 10,361,022 | 1,139,587 | 9.09 | b |
| 14 | 2006 | 796,212 | 34,627 | 22.99 | 11,218,298 | 940,290 | 11.93 | b |
| 15 | 2007 | 1,157,285 | 53,287 | 21.72 | 9,849,516 | 873,816 | 11.27 | b |
| 16 | 2008 | 585,809 | 31,009 | 18.89 | 4,707,897 | 347,870 | 13.53 | b |
| | Projected | | | | | | | |
| 17 | 2008 | 836,538 | 39,088 | 21.40 | 8,107,182 | 722,280 | 11.22 | b |
| 18 | 2009 | 498,400 | 23,288 | 21.40 | 10,013,680 | 892,133 | 11.22 | b |
| | Citizens Projected | | | | | | | |
| 19 | 2008 | 738,372 | 39,088 | 18.89 | 9,772,448 | 722,280 | 13.53 | Testimony |
| 20 | 2009 | 439,910 | 23,288 | 18.89 | 12,070,559 | 892,133 | 13.53 | Testimony |
| | Projected Difference | | | | | | | |
| 21 | 2008 | (98,166) | | | 1,665,266 | | | L.19-L.17 |
| 22 | 2009 | (58,490) | | | 2,056,879 | | | L.20-L.18 |

Source: (a) Company response to OPC Interrogatory No. 70.
(b) Company response to OPC Interrogatory No. 72.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Plant Adjustments - Mains/Services

Docket No. 080318-GU
Exhibit HWS-1
Schedule B-4


| Line No. | Description | 376 | 376.02 | 380.02 | Total | Reference |
|---|---|---|---|---|---|---|
| 1 | 2008 Plant Adjustment | (3,070,892) | (10,206,925) | 1,665,266 | | Schedule B-3 |
| 2 | 2008 Average | (1,535,446) | (5,103,463) | 832,633 | | L.1 x 50% |
| 3 | Depreciation Rate | 4.00% | 2.90% | 5.10% | | a |
| 4 | 2008 Depreciation | (61,418) | (148,000) | 42,464 | | L.2 x L.3 |
| 5 | 2009 Depreciation | (94,277) | (459,170) | 148,547 | | Schedule C-9 |
| 6 | 2009 Average | (47,138) | (229,585) | 74,274 | | L.5 x 50% |
| 7 | Accum. Deprec. Adj. | (108,556) | (377,586) | 116,738 | (369,404) | L.4 + L.6 |

Source: (a) Company Schedule G-2, Page 23.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Adjusted Net Operating Income

Docket No. 080318-GU
Exhibit HWS-1
Schedule C-1


| Line No. | Description | Per Company Amount | Citizens Adjustments | Per Citizens Amount | Reference |
|---|---|---|---|---|---|
| 1 | Operating Revenues | 169,906,126 | 1,500,000 | 171,406,126 | Sch. C-2 |
| | Operating Expenses | | | | |
| 2 | Cost Of Gas | 0 | | 0 | |
| 3 | Operation & Maintenance | 72,608,899 | (7,010,467) | 65,598,432 | Sch. C-2 |
| 4 | Depreciation & Amortization | 43,164,733 | (404,900) | 42,759,833 | Sch. C-2 |
| 5 | Amortization Other | 640,000 | | 640,000 | |
| 6 | Taxes Other Than Income | 10,823,933 | | 10,823,933 | |
| 7 | Interest Synchronization | 267,636 | | 267,636 | |
| 8 | Income Taxes Federal | 5,722,844 | 3,664,416 | 9,387,260 | Sch. C-2 |
| 9 | Income Taxes State | 1,201,994 | | 1,201,994 | |
| 10 | Deferred Taxes Federal | 1,927,731 | | 1,927,731 | |
| 11 | Deferred Taxes State | 83,980 | | 83,980 | |
| 12 | Investment Tax Credits | 0 | | 0 | |
| 13 | Gain On Sale Of Property | (480,321) | | (480,321) | |
| 14 | Total Operating Expenses | 135,961,429 | (3,750,951) | 132,210,478 | |
| 15 | Operating Income | 33,944,697 | 5,250,951 | 39,195,648 | |

Peoples Gas System
Projected Test Year Ended December 31, 2009

Net Operating Income Adjustments



| Line No. | Description | Per Citizens Amount | Reference |
|---|---|---|---|
| | Revenue | | |
| 1 | Off-System Sales | 1,500,000 | Schedule C-3 |
| | O&M Expenses | | |
| 2 | Payroll | (210,199) | Schedule C-4 |
| 3 | Incentive Compensation | (2,714,400) | Testimony |
| | Employee Benefits | | |
| 4 | - Employee Welfare/Activity | (172,881) | Schedule C-5 |
| 5 | - Executive Stock Grants/Options | (569,500) | Testimony |
| 6 | Pipeline Integrity Expense | (250,000) | Testimony |
| 7 | Directors & Officers Liability | (342,000) | Testimony |
| 8 | Storm Damage | (100,000) | Testimony |
| 9 | Rate Case Expense | (113,100) | Schedule C-6 |
| 10 | TPI Marketing Contract | (2,000,530) | Schedule C-7 |
| 11 | Tampa Electric Charges | (1,261,437) | Schedule C-8 |
| 12 | Uncollectibles Mechanism Reversal | 723,580 | Testimony |
| 13 | Total O&M Expense | (7,010,467) | |
| 14 | Depreciation Expense | (404,900) | Schedule C-9 |
| 15 | Interest Synchronization Tax Adjustment | 225,313 | Schedule C-10 |
| 16 | Income Tax Adjustment | 3,439,103 | Schedule C-11 |

Peoples Gas System
Projected Test Year Ended December 31, 2009

Docket No. 080318-GU
Exhibit HWS-1
Schedule C-3
Page 1 of 1

Off-System Sales Adjustment

| Line No. | Year | OSS Gross Margin | PGA | OSS Net Revenue | Reference |
|---|---|---|---|---|---|
| 1 | 2003 | 6,311,388 | 4,733,541 | 1,577,847 | a |
| 2 | 2004 | 3,385,504 | 2,539,128 | 846,376 | a |
| 3 | 2005 | 10,525,292 | 7,893,969 | 2,631,323 | a |
| 4 | 2006 | 12,986,868 | 9,740,151 | 3,246,717 | a |
| 5 | 2007 | 11,962,076 | 8,971,557 | 2,990,519 | a |
| 6 | Five Year Average | | | 2,258,556 | |
| 7 | 2008 | 5,788,748 | 4,341,561 | 1,447,187 | a |
| 8 | 2008 Annualized | | | 2,170,781 | |
| | | | | 2009 Estimate | |
| 9 | Per OPC | | | 2,000,000 | |
| 10 | Per Company | | | 500,000 | |
| 12 | OSS Revenue Adjustment | | | 1,500,000 | |

Source: (a) Company response to OPC Interrogatory No. 51.
(b) Company response to OPC Interrogatory No. 71.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Payroll Trending Adjustment

Docket No. 080318-GU
Exhibit HWS-1
Schedule C-4
Page 1 of 1

| Line No. | Account | Per Company Base Year | Per Company Projected Test Year | Citizens Projected Test Year | Trend Adjustment | Company Reference |
|---|---|---|---|---|---|---|
| 1 | 870 | 275,158 | 296,180 | 296,180 | 0 | a |
| 2 | 871 | 1,767 | 1,927 | 1,902 | (25) | a |
| 3 | 872 | (6,821) | (7,440) | (7,342) | 98 | a |
| 4 | 874 | 4,097,378 | 4,469,301 | 4,410,418 | (58,883) | a |
| 5 | 875 | 110,783 | 119,247 | 119,247 | (0) | a |
| 6 | 876 | 833 | 897 | 897 | (0) | a |
| 7 | 877 | 22,300 | 24,004 | 24,004 | (0) | a |
| 8 | 878 | 2,164,614 | 2,361,098 | 2,329,991 | (31,107) | a |
| 9 | 879 | 1,768,494 | 1,929,022 | 1,903,607 | (25,415) | a |
| 10 | 880 | 619,491 | 666,820 | 666,820 | 0 | a |
| 11 | 886 | 24,255 | 26,457 | 26,108 | (349) | a |
| 12 | 887 | 1,009,551 | 1,101,189 | 1,086,681 | (14,508) | a |
| 13 | 889 | 174,547 | 190,391 | 187,882 | (2,509) | a |
| 14 | 890 | 315,580 | 344,225 | 339,690 | (4,535) | a |
| 15 | 891 | 275,317 | 300,308 | 296,351 | (3,957) | a |
| 16 | 892 | 393,685 | 429,420 | 423,763 | (5,657) | a |
| 17 | 893 | 250,047 | 272,744 | 269,151 | (3,593) | a |
| 18 | 894 | 33,661 | 36,716 | 36,233 | (483) | a |
| 19 | 902 | 1,115,028 | 1,216,240 | 1,200,216 | (16,024) | a |
| 20 | 903 | 2,419,761 | 2,639,405 | 2,604,631 | (34,774) | a |
| 21 | 912 | 4,865 | 5,307 | 5,237 | (70) | a |
| 22 | 920 | 6,060,293 | 6,523,299 | 6,523,299 | 0 | a |
| 23 | 921 | 281,641 | 307,206 | 303,158 | (4,048) | a |
| 24 | 925 | 303,239 | 330,764 | 326,406 | (4,358) | a |
| 25 | 926 | 6,699 | 7,211 | 7,211 | (0) | a |
| 26 | 932 | 37,298 | 40,148 | 40,148 | (0) | a |
| 27 | Total | | 23,632,086 | 23,421,887 | (210,199) | |

Source: (a) Company Schedule G-2, Pages 10-19.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Employee Benefit Adjustment



| Line No. | Description | 2007 | 2009 | Reference |
|---|---|---|---|---|
| | Per Citizens | | | |
| 1 | Employee Welfare/Activity Expense | 211,375 | 225,900 | a |
| 2 | New Welfare Costs | 0 | 0 | |
| 3 | Regulatory Adjustment | (122,720) | (131,081) | Testimony |
| 4 | Net Expense | 88,655 | 94,819 | L.1-L.3 |
| | Per Company | | | |
| 5 | Employee Welfare/Activity Expense | 211,375 | 225,900 | a |
| 6 | New Welfare Costs | 0 | 164,500 | c |
| 7 | Regulatory Adjustment | (114,000) | (122,700) | b |
| 8 | Expensed Per Company | 97,375 | 267,700 | |
| 9 | Expense Adjustment Employee Welfare | | (172,881) | L.3-L.7 |

Source: (a) Company response to OPC Interrogatory No. 6.
(b) Company Schedule C-2 and G-2.
(c) Company response to OPC POD No. 47.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Rate Case Expense Adjustment

Docket No. 080318-GU
Exhibit HWS-1
Schedule C-6
Page 1 of 1

| Line No. | Description | Per OPC | Per Company | Recommended Adjustment | Company Reference |
|---|---|---|---|---|---|
| 1 | C,H. Guernsey & Co. | 48,000 | 45,000 | 3,000 | a |
| 2 | Yardley & Associates | 70,000 | 70,000 | 0 | a |
| 3 | Huron Consulting | 163,000 | 200,000 | (37,000) | a |
| 4 | Black & Veatch | 7,500 | 7,500 | 0 | a |
| 5 | F Sivard | 10,000 | 10,000 | 0 | a |
| 6 | AUS Consulting | 38,500 | 45,000 | (6,500) | a |
| 7 | C Holden | 25,000 | 50,000 | (25,000) | a |
| 8 | Legal | 250,000 | 250,000 | 0 | a |
| 9 | Other | 72,500 | 72,500 | 0 | a |
| 10 | Total | 684,500 | 750,000 | (65,500) | |
| 11 | Amortization | 136,900 | 250,000 | (113,100) | |
| 12 | End of Year 2009 | 547,600 | 500,000 | 47,600 | |
| 13 | Average Balance | 616,050 | 625,000 | (8,950) | |

Source: (a) Company response to OPC Interrogatory No. 46 and OPC POD No. 65.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Marketing Expense Adjustment

Docket No. 080318-GU
Exhibit HWS-1
Schedule C-7


| Line No. | Description | Per OPC | Per Company | Recommended Adjustment | Company Reference |
|---|---|---|---|---|---|
| 1 | Fixed Amount | 3,981,900 | 3,981,900 | 0 | a |
| 2 | Variable Amount | 143,570 | 2,144,100 | (2,000,530) | a |
| 3 | Total | 4,125,470 | 6,126,000 | (2,000,530) | |
| | Variable Calculation | | | | a |
| 4 | New Customers | 1,298 | | | b |
| 5 | Targeted Signings | 12,000 | | | a |
| 6 | Percentage Achieved | 10.82% | | | L. 4/L.5 |
| 7 | Divisor | 2 | | | a |
| 8 | Allowed Percentage | 5.41% | | | L.6/L.7 |
| 9 | Variable Factor | 2,654,600 | ($2,600,000 x 1.021) | | a |
| 10 | Variable Earned | 143,570 | | | L.8 x L.9 |

Source: (a) Company response to OPC POD No. 51.
(b) Company response to OPC Interrogatory No. 78.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Tampa Electric Charges Account 921 Expense Adjustment

Docket No. 080318-GU
Exhibit HWS-1
Schedule C-8


| Line No. | Description | Total Cost | Reference |
|---|---|---|---|
| 1 | Allocated Cost 2007 - 590 Expense Code | 4,445,825 | a |
| 2 | 2009 Allocated Cost - 590 Expense Code | 3,990,000 | b |
| 3 | 2009 to 2007 ratio | 89.75% | L.2/L.1 |
| 4 | 2007 Allocated Success Sharing | (321,652) | a |
| 5 | 2007 Allocated Stock Grant | (708,010) | a |
| 6 | 2007 Allocated DOL Insurance | (375,884) | a |
| 7 | Total 2007 Allocated Cost Subject to Adjustment | (1,405,546) | |
| 8 | Estimated 2009 Allocated Cost Adjustment | (1,261,437) | |

Source: (a) Company response to OPC POD No. 47.
(b) Company response to OPC Interrogatory No. 45.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Depreciation Expense Adjustment

Docket No. 080318-GU
Exhibit HWS-1
Schedule C-9


| Line No. | Description | Account 376 | Account 376.02 | Account 380.02 | Total | Reference |
|---|---|---|---|---|---|---|
| 1 | Plant Adjustment | (2,356,919) | (15,833,458) | 2,912,691 | (15,277,686) | |
| 2 | Depreciation Rate | 4.00% | 2.90% | 5.10% | | a |
| 3 | Expense Adjustment | (94,277) | (459,170) | 148,547 | (404,900) | |

Source: (a) Company Schedule G-2, Page 23.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Interest Synchronization Adjustment

Docket No. 080318-GU
Exhibit HWS-1
Schedule C-10


| Line No. | Description | Amount | Reference |
|---|---|---|---|
| 1 | Rate Base Per Citizen's | 548,682,201 | Schedule B-1 |
| 2 | Weighted Cost of Debt (plus customer deposits | 3.28% | Schedule D |
| 3 | Interest Deduction | 18,012,851 | L.1 x L.2 |
| 4 | Interest Deduction in Filing | 19,290,750 | a |
| 5 | Difference | (1,277,899) | L.3 - L.4 |
| 6 | Composite Tax Rate | 38.575% | |
| 7 | Increase (Decrease) In Income Tax Expense | 492,949 | L.5 x L.6 |
| 8 | Interest Synchronization In Filing | 267,636 | b |
| 9 | Increase (Decrease) in Income Tax Expense | 225,313 | |

Source: (a) Company Schedule G-2, Page 30.
(b) Company Schedule G-2, Page 3.

Peoples Gas System
Projected Test Year Ended December 31, 2009

Income Tax Expense

Docket No. 080318-GU
Exhibit HWS-1
Schedule C-11


| Line No. | Description | Amount | Reference |
|---|---|---|---|
| 1 | Operating Income Adjustments | 8,915,367 | Schedule C-1 |
| 2 | Composite Income Tax Rate | 38.575% | |
| 3 | Increase (Decrease) to Income Tax Expense | 3,439,103 | L.1 x L.2 |

Peoples Gas System
Projected Test Year Ended December 31, 2009

Overall Cost of Capital

Docket No. 080318-GU
Exhibit HWS-1
Schedule D
Page 1 of 1

| Line No. | Description | Capital | Ratio | Cost Rate | Weighted Cost Rate |
|---|---|---|---|---|---|
| 1 | Long Term Debt | 222,773,987 | 39.53% | 7.20% | 2.85% |
| 2 | Short Term Debt | 3,456,397 | 0.61% | 1.76% | 0.01% |
| 3 | Common Equity | 273,561,565 | 48.54% | 9.25% | 4.49% |
| 4 | Customer Deposits - Res. | 9,338,641 | 1.66% | 6.00% | 0.10% |
| 5 | Customer Deposits - Comm | 26,309,935 | 4.67% | 7.00% | 0.33% |
| 6 | Inactive Deposits | 480,368 | 0.09% | 0.00% | 0.00% |
| 7 | Deferred Taxes | 27,670,682 | 4.91% | 0.00% | 0.00% |
| 8 | Tax Credit | 7,862 | 0.00% | 0.00% | 0.00% |
| 9 | | 563,599,437 | 100.00% | | 7.77% |
| 10 | Weighted Cost of Debt (plus customer deposits) | | | | 3.28% |

Source: Per Citizen's witness Dr. J.R. Woolridge.

**CERTIFICATE OF SERVICE**
**DOCKET NO. 080318-GU**

I HEREBY CERTIFY that a true and correct copy of the Direct Testimony of Helmuth W. Schultz, III, has been furnished by hand delivery or U.S. Mail to the following parties on this 18th day of December, 2008.

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