Docket Nos. 09-0166/09-0167
Consolidated
ICC Staff Exhibit 15.0

REBUTTAL TESTIMONY

of

Dianna Hathhorn
Accountant

Accounting Department
Financial Analysis Division
Illinois Commerce Commission

Proposed General Increase in Gas Rates

North Shore Gas Company

The Peoples Gas Light and Coke Company

Docket Nos. 09-0166 and 09-0167 Consolidated

August 4, 2009

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SCHEDULES

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<u>Witness Identification</u>

Q. Please state your name and business address.

A. My name is Dianna Hathhorn. My business address is 527 East Capitol Avenue, Springfield, Illinois 62701.

Q. Have you previously filed testimony in this proceeding?

A. Yes, my direct testimony is ICC Staff Exhibit 1.0.

<u>Purpose of Testimony</u>

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is as follows:

1. to present the Staff adjusted operating statements and rate base of The Peoples Gas Light and Coke Company ("Peoples Gas") and North Shore Gas Company ("North Shore") (individually, the "Company" and collectively, the "Companies"); and
2. to respond to the Companies' opposition to my adjustments for incentive compensation, non-union and union wages, and, for Peoples Gas only, expenses related to Docket No. 06-0311 (Liberty Audit);
3. to update my calculation of invested capital taxes;

4. to respond to The People of the State of Illinois/The Citizens Utility Board/The City of Chicago ("AG/CUB/City") witness Mr. Effron's payroll adjustment;
5. to respond to the Companies concerning my proposed revisions to Rider ICR; and
6. to respond to the Companies concerning my recommendations regarding Rider VBA.

Q. Are you sponsoring any schedules as part of your rebuttal testimony?

A. Yes. I prepared (or supervised the preparation of) the following schedules for the Companies, which show data as of, or for the test year ending, December 31, 2010:

<u>Revenue Requirement Schedules</u>

Schedules 15.1 P and N - Statement of Operating Income with Adjustments
Schedules 15.2 P and N- Adjustments to Operating Income
Schedules 15.3 P and N- Rate Base
Schedules 15.4 P and N - Adjustments to Rate Base
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Schedules 15.6 P and N - Gross Revenue Conversion Factor

<u>Adjustment Schedules</u>

Schedules 15.7 P and N-	Incentive Compensation Adjustment
Schedules 15.8 P and N-	Non-Union Base Wages Adjustment
Schedules 15.9 P and N-	Invested Capital Taxes Adjustment
Schedules 15.10 P -	Liberty Audit Adjustment

Q. Please explain the P and N suffixes that appear with your schedule numbers.

A. These suffixes indicate the Company to which a particular schedule applies. The P suffix identifies a schedule that applies to Peoples Gas, and the N suffix identifies a schedule that applies to North Shore.

Attachments

Q. Have you included any attachments as part of your direct testimony?

A. Yes, I have included the following attachments:

Attachment A	Companies' responses to Staff Data Request DLH-1.06 SUPP Attach 01.2 Public
Attachment B	Companies' responses to Staff Data Request DLH-1.06 SUPP Attach 01.1 Public
Attachment C	Companies' responses to Staff Data Request DLH-1.06 2SUPP Attach 03 Public
Attachment D	Companies' responses to Staff Data Request PGL-DLH-1.08a SUPP Attach 01 Public and NS-DLH-1.08a 2SUPP Attach 01 Public
Attachment E	Companies' responses to Staff Data Request DLH-21.01
Attachment F	Companies' responses to Staff Data Request DLH-8.06
Attachment G	Peoples Gas response to Staff Data Request DLH-23.04

Attachment H	Companies' responses to Staff Data Request DLH-23.01

Revenue Requirement Schedules

Q. Please describe ICC Staff Exhibit 15.0, Schedules 15.1 P and N, Statement of Operating Income with Adjustments.

A. Schedules 15.1 P and N, are the same as ICC Staff Exhibit 1.0, Schedules 1.1 P and N, described in my direct testimony, except that they incorporate the Companies' rebuttal positions reflected in Peoples Gas and North Shore Exhibits NS-PGL Ex. SM-2.0 and NS-PGL Ex. JH-2.0, and Staff's rebuttal positions.

Q. Please describe ICC Staff Exhibit 15.0, Schedules 15.2 P and N, Adjustments to Operating Income.

A. These schedules identify Staff's adjustment to Operating Income. The source of each adjustment is shown in the heading of each column. Column (y) from page 3 of 3 for Peoples Gas and column (q) from page 2 of 2 for North Shore are carried forward to ICC Staff Exhibit 15.0, Schedules 15.1 P and N, Column (c).

Q. Please describe ICC Staff Exhibit 15.0, Schedules 15.3 P and N, Rate Base.

A. Schedules 15.3 P and N are the same as ICC Staff Exhibit 1.0, Schedules 1.3 P and N described in my direct testimony, except that they incorporate the Companies' and Staff's rebuttal positions.

Q. Please describe ICC Staff Exhibit 15.0, Schedules 1.4 P and N, Adjustments to Rate Base.

A. Schedules 15.4 P and N identify Staff's adjustments to rate base. The source of each adjustment is shown in the heading of each column. Column (q) from page 2 of 2 for Peoples Gas and Column (i) from page 1 of 1 for North Shore are carried forward to ICC Staff Exhibit 15.0, Schedules 15.3 P and N, Column (c).

Interest Synchronization

Q. Please explain ICC Staff Exhibit 15.0, Schedules 15.5 P and N, Interest Synchronization Adjustment.

A. Schedules 15.5 P and N use the same concept as ICC Staff Exhibit 1.0, Schedules 15.5 P and N. The theory is discussed at page 7 of my direct testimony.

Gross Revenue Conversion Factor

Q. What is the purpose of ICC Staff Exhibit 15.0, Schedule 15.6 P and N, Gross Revenue Conversion Factor?

A. Schedule 15.6 uses the same concept as ICC Staff Exhibit 1.0, Schedule 1.6. The theory is discussed in my direct testimony. (ICC Staff Ex. 1.0, p. 7, lines 149-154)

Uncontested Adjustments

Q. Did the Companies accept any adjustments from Staff's direct testimony?

A. Yes. The following adjustments were accepted by the Companies and are therefore included in the Companies' beginning rebuttal position numbers in Staff Schedules 15.1 P and N (Operating Statement) and 15.3 P and N (Rate Base).

1. Schedule 1.8 P- Non-Union Wages (Partial agreement)
2. Schedules 1.9 P and N- Union Wages
3. Schedules 1.10 P and N-Reduction in IBS Charges (Incorporated by adoption of AG/CUB/City Schedule C-2)
4. Schedules 1.11 P and N-Inventory Reclassification
5. Schedules 1.12 P and N-Invested Capital Taxes (Derivative adjustment to be updated through Final Order)
6. Schedule 1.13 P-Liberty Audit (Partial agreement - outside contractors)
7. Schedules 2.2 P and N Outside Contractors (Incorporated by adoption of AG/CUB/City Schedule C-2)
8. Schedules 3.4 P and N-Budget Payment Plans
9. Schedules 3.5 P and N-Customer Deposits
10. Schedules 5.1 P and N-Real Estate Taxes
11. Schedules 6.1 P and N-Lobbying Expense
12. Schedules 6.2 P and N-Social and Service Club Dues
13. Schedules 6.3 P and N-Advertising Expenses (partial agreement)

14. Schedules 6.4 P and N-Civic, Political and Related Activities
15. Schedules 13.4P and 13.5 N Adjusted Fuels Costs (Staff does not contest Companies' update-ICC Staff Ex. 26.0 Seagle)

Since the Companies agreed with my proposal to calculate the incremental increase in State invested capital taxes based upon the final Commission approved rate of return and rate base, (NS-PGL Ex. SM-2.0, p. 4), I have updated my calculation for Staff's rebuttal positions and reflected the adjustment on Schedules 15.9 P and N, Invested Capital Taxes Adjustment.

Q. Did the Companies accept any adjustments from Intervenors' direct testimony?

A. Yes. The following adjustments were proposed by Intervenors, accepted by the Companies, and Staff has no objection to the adjustments; therefore, these are also included in the Companies' beginning rebuttal position numbers in Staff Schedules 15.1 P and N (Operating Statement) and 15.3 P and N (Rate Base).

1. AG/CUB/City Exhibit 1.0, Schedule C-2- Reduction in IBS Charges
2. AG/CUB/City Exhibit 1.0, Schedule C-2- IBS Account 930.20 Mainframe Depreciation

Q. Did the Companies contest any adjustments from Staff's direct testimony that Staff no longer proposes?

A. Yes, Schedules 3.2 P and N Office Supplies and Expense Adjustment.

<u>Contested Adjustments</u>

Q. Does Staff contest any adjustments from Intervenor direct testimony the Companies oppose?

A. Yes.

1. AG/CUB/City Exhibits 1.1 and 1.2, Schedules C-2.1- Payroll Adjustment (addressed in my testimony below)
2. AG/CUB/City Exhibit 1.0, Schedule C-2- Regulatory (Rate Case Expense) Adjustment (Peoples Gas only) (addressed by Staff witness Ostrander, ICC Staff Ex. 17.0)
3. AG/CUB/City Exhibit 1.0, Schedule C-2- Savings Plan Adjustment (addressed by Staff witness Pearce, ICC Staff Ex. 16.0)
4. AG/CUB/City Exhibit 1.0, Schedule C-2- Sales Forecast Adjustment: Staff agrees with AG/CUB/City witness Effron that the sales forecasts should be modified to reflect a more current forecast of 2010 gas prices (ICC Staff Ex. 24.0). However a revenue adjustment to present rates is unnecessary to calculate the final approved rates and revenues for this rate case, therefore Mr. Effron's adjustment is not reflected in Schedules 15.1 P and N.

Q. Has Staff adopted any adjustments from Intervenor direct testimony the Companies oppose?

A. Staff proposes the adjustments below for corrections or updates in pricing from adjustments in AG/CUB/City Exhibit 1.0:

1. Schedules 27.3 P and 27.1 N-Gas in Storage Adjustment (Seagle/Rearden)
2. Schedules 27.4 P and N- Company Use Gas Adjustment (Seagle/Rearden)
3. Schedules 27.5 N - Franchise Requirements Adjustment (Seagle/Rearden)

Q. Please provide a listing of the remaining contested Staff adjustments.

A. The remaining contested Staff adjustments, using Staff's rebuttal schedule references, are as follows:

1. Schedules 15.7 P and N-Incentive Compensation Adjustment (Hathhorn)
2. Schedules 15.8 P and N-Non-Union Wages Adjustment (Hathhorn)
3. Schedule 15.10 P-Liberty Audit Adjustment (Hathhorn)
4. Schedules 16.1 P and N-Pension Asset (Pearce)
5. Schedules 16.2 P and N-Merger Costs & Savings (Pearce)
6. ICC Staff Ex. 16.0-Regulatory Asset Correction (Pearce)
7. Schedules 17.1 P and N-Cash Working Capital (Ostrander)
8. Schedules 17.2 P and N-Injuries and Damages (Ostrander)
9. Schedules 18.1 P and N and ICC Staff Ex. 27.0-Recoverable Cushion Gas (Everson/Seagle/Rearden)
10. Schedules 18.2 P and N and ICC Staff Ex. 27.0-Non-Recoverable Cushion Gas (Everson/Seagle/Rearden)
11. Schedules 18.3 P and ICC Staff Ex. 27.0-Gathering System Phase 2 (Everson/Seagle)
12. Schedules 18.4 P and ICC Staff Ex. 27.0-Gathering System Pigging (Everson/Seagle)
13. Schedules 19.1 P and N-Uncollectibles Expense (Bridal/Rearden)

14. Schedules 20.1 P and N-Advertising Expense (Wilcox)

Incentive Compensation Adjustment

Q. Please describe ICC Staff Exhibit 15.0, Schedules 15.7 P and N, Incentive Compensation Adjustment.

A. Schedules 15.7 P and N reflect my proposed adjustments to reduce each Company's operating expenses and rate base for incentive compensation expenses. The adjustment is the same as reflected on Schedule 1.7 P and N, pages 2 through 5, and summarized on page 1 of Schedule 1.7 P and N, except for a correction of the calculation of accumulated deferred income taxes.

Q. Did the Companies accept any portion of your adjustments?

A. No. Therefore, for the purpose of a complete record I am attaching to my testimony the following attachments of the Companies' responses to Staff Data Requests concerning the incentive compensation plans which I discussed in my direct testimony:

Attachment A	Companies' responses to Staff Data Request DLH-1.06 SUPP Attach 01.2 Public (Executive Incentive Plan description)
Attachment B	Companies' responses to Staff Data Request DLH-1.06 SUPP Attach 01.1 Public (Non-Executive Incentive Plan description)

Attachment C	Companies' responses to Staff Data Request DLH-1.06 2SUPP Attach 03 Public (Table of plan measures and weightings)
Attachment D	Companies' responses to Staff Data Request PGL-DLH-1.08a SUPP Attach 01 Public and NS-DLH-1.08a 2SUPP Attach 01 Public (Table of 2007 and 2008 Results)
Attachment E	Companies' responses to Staff Data Request DLH-21.01 (Description of 2009 Plan Change)
Attachment F	Companies' responses to Staff Data Request DLH-8.06 (Description of Stock Plans)

Q. The Companies oppose your adjustment for the Executive Incentive Plan costs because according to them it "fulfills a legitimate purpose, and is not excessive…and, as a result, is prudent." (NS-PGL Ex. JCH-1.0, p. 3, lines 62-63, 66) Do you agree with the Companies that the Executive Incentive Plan fulfills a legitimate purpose and is prudent?

A. I disagree with the Companies' criteria for rate recovery of incentive compensation expense. My opinion is based on several Commission orders which expressly state that: a) costs paid out solely on achievement of financial goals should be paid by shareholders; and b) costs of achievement of non-financial goals must demonstrate tangible benefits to ratepayers.[1] The Executive Incentive Plan fails both tests. First, its payout is primarily based not only upon Peoples Gas' and North Shore's net income, but also upon the achievement of the following financial measures of their affiliates: 1) Integrys Energy Group, Inc.'s ("IEG" or "Integrys Energy Group") consolidated net income, 2) Integrys' combined regulated subsidiaries net income, and 3) Integrys Energy Services' net income.[2] Therefore, the affiliates' financial success or failure directly impacts Peoples Gas' and North Shore's test year incentive compensation costs. All of these financial measures primarily benefit shareholders rather than ratepayers.

Second, the Executive Incentive Plan's non-financial or performance goals costs are flawed in multiple ways. The costs are based upon goals unlikely to be achieved based upon the Companies' past performance. As I discuss below, the Companies both achieved below target levels for their safety goals, and Peoples Gas did not attain the target level for its reduction in system leaks goal, The costs are also based upon the Companies' affiliates' success or failure rates.[3] Finally, the Executive Incentive Plan was modified in 2009 wherein if the IEG Consolidated Net Income threshold is not reached, any earned non-financial measures payouts will be reduced by fifty (50) percent.[4]

[1] ICC Staff Ex. 1.0, pp. 18-25
[2] ICC Staff Ex. 1.0, p. 9, lines 184-190 and ICC Staff Ex. 15.0, Attachment A
[3] ICC Staff Ex. 1.0. pp. 9-13, and ICC Staff Ex. 15.0, Attachments C and D
[4] ICC Staff Ex. 1.0, p. 14, lines 283-291 and ICC Staff Ex. 15.0, Attachment E

Q. Do you agree with the Companies that the Executive Incentive Plan cost is not excessive?

A. Again, I disagree with the Companies' criteria for rate recovery of incentive compensation expense. My adjustment is not based on the amount of the Executive Incentive Plan, but rather on the failure to meet criteria ordered by the Commission, discussed above. Further, an expense may not be allowable in rates even if it is not "excessive." Lobbying expenses are an example of this scenario, since they are barred from rate recovery no matter the amount.[5] The Commission orders that I discussed in direct testimony did not appear to base their conclusions on the amount of the adjustment, but rather on the facts of the specific incentive compensation plans at issue.

Q. The Companies acknowledge that "…the ICC has previously approved measures that are specifically related to cost control or to cost reduction, although it has not approved the net income measure." (NS-PGL Ex. JCH-1.0, p. 4, lines 76-78) Please respond to the Companies' contention that to the extent net income is a "hybrid of revenue and cost, the costs associated with the Utilities' Executive Incentive Plan should be allowed even under the logic of the Commission's standards."

[5] Section 9-224 of 220 ILCS 5 Public Utilities Act

A. The Companies misrepresent the Commission standards. The Companies are correct that the Commission has repeatedly denied cost recovery of incentive compensation costs based upon achievement solely of a net income level, a goal determined to benefit shareholders primarily over ratepayers. Net income is a result of revenues minus costs. However in this case, the Companies have made no showing that any specific cost reduction goals exist, are related to Peoples Gas' or North Shore's operations, or are reflected in the test year expense. Rather, the test year net income goals are determined on an Integrys Energy Group consolidated basis and include the results of both regulated and unregulated Peoples Gas' and North Shore's affiliates.

Q. The Companies present a discussion of the Executive Incentive Plan's non-financial measures and conclude that, "in summary, these measures have a direct impact to customers." (NS-PGL Ex. JCH-1.0, pp. 5-6, lines 92-116) Please respond.

A. To consider a plan's costs for rate recovery, the plan along with the company's historical plan achievements must be considered. For example, at lines 107-109 of NS-PGL Ex. JCH-1.0, the Companies contend the reduction in systems leaks goal is a direct benefit to customers; however, Peoples Gas achieved below target for this goal in

2008.[6] Further, at lines 100-103, the Companies discuss the employee safety measures goal; however, the Companies both performed below target in 2007 and 2008 in this category.[7] These results call into question the Companies' test year forecasts based upon achieving target level results. Further, the non-financial goals are also tied to the Companies' affiliates' performance results in their non-financial goals, and IEG's consolidated net income.

Q. The Companies argue that their performance goals based upon the achievement of Peoples Gas' and North Shore's affiliates represent a "team-based Company philosophy" wherein the Companies share best-practices which benefits Illinois customers. The Companies further state that "all subsidiaries share in staff support and should share in the support expense." (NS-PGL Ex. JCH-1.0, p. 6) Please respond.

A. Following this logic would lead to the unreasonable requirement that the Commission analyze in this record the Companies' affiliates' performance goal results in Minnesota, Michigan, and Wisconsin. The Companies must be able to demonstrate in this proceeding's record the benefits of incentive compensation expense to Illinois ratepayers. The Companies are free to design their plans using a team-based philosophy, but are not

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[6] ICC Staff Ex. 1.0 p. 11, lines 218-226 and ICC Staff Ex. 15.0 Attachment D
[7] ICC Staff Ex. 1.0 p. 11, lines 227-236

exempt from the rate recovery criteria established by the Commission over a number of consistent orders.

Q. The Companies discuss their compensation philosophy and conclude that "[a]ttracting and retaining a sufficient, qualified and motivated work force benefits the Utilities' customers by making sure there are enough employees to perform needed work, by maintaining and improving the productivity and quality of work, and by reducing the expenses associated with recruiting and training new employees." (NS-PGL Ex. JCH-1.0, pp. 7-8, quoting lines 161-164) Are the test year costs directly based upon these goals?

A. No. As discussed above, the goals that trigger the test year incentive compensation costs are not based upon this statement, but rather the specific goals and measures identified in ICC Staff Ex. 15.0, Attachments A, B, and C. My adjustment is based upon the Commission's criteria for rate recovery-- for the utility to demonstrate tangible benefits to ratepayers--established in a number of Commission orders.

Q. Did the Companies agree that the Executive Incentive Plan and Non-Executive Incentive Plan are essentially the same except for the weightings of the financial versus non-financial goals and the proportionate share of performance goals costs based upon the Companies' affiliates goals?

A. Yes. (NS-PGL Ex. JCH-1.0, p. 8) Therefore, my direct and rebuttal testimonies concerning the Executive Incentive Plan apply as well to the Non-Executive Incentive Plan.

Q. The Companies also oppose the sub-part of your adjustment to remove the incentive compensation costs of its stock-based plans since the "stock plans are designed to attract and retain a qualified and motivated workforce." (NS-PGL Ex. JCH-1.0, p. 9) Please respond.

A. There is no debate that the stock plans are based solely on financial goals that primarily benefit shareholders.[8] The Companies were denied cost recovery of their restricted stock and performance shares plan costs in their last rate cases since they failed to demonstrate cost savings or other direct ratepayer benefit:[9]

> "We agree with Staff that three of the five plans (STIC, Affiliate Charges, Restricted Stock & Performance Shares) fail to demonstrate the cost savings or other direct ratepayer benefit that we require." (ICC Docket Nos. 07-0241/07-0242 Cons.(Order, February 5, 2008) p. 66)

The record is lacking a demonstration of cost savings or other direct ratepayer benefit in the instant case as well.

[8] ICC Staff Ex. 1, pp. 15-16, lines 322-342 and Staff Ex. 15.0, Attachment F

Q. Do the Companies agree that they did not make entries to remove disallowed capitalized incentive compensation from rate base denied by the Commission in Docket Nos. 07-0241/0242 (cons.)?

A. Yes, the Companies maintain these amounts should be included in rate base in this proceeding since its appeal remains pending. (NS-PGL Ex. JH-2.0, p. 16) However, it is my understanding that rulings of the Commission remain valid unless and until they are reversed or set aside by a reviewing court. The rates set in this case should not include amounts that the Commission has already disallowed.

Q. Did any other witnesses address the issue of incentive compensation expenses?

A. Yes, AG/CUB/City witness Mr. Effron also proposed an adjustment to remove these costs from the Companies' test year filing. However, his adjustment does not include all test year incentive compensation costs, since it does not include costs identified by the Companies later in their responses to discovery (Companies responses to Staff Data Requests DLH-8.02, DLH-13.02, DLH-13.03).[10] The Companies did not dispute the calculation of my adjustment. Also, the AG/CUB/City advocates a disallowance of 50% of incentive compensation paid directly to the

[9] ICC Staff Ex. 1, p. 18, lines 388-391

employees of the Companies, and 100% disallowance of incentive compensation allocated from affiliates. (AG/CUB/City Ex. 1.0, p. 21) I am not aware of the Commission strictly using these criteria -- direct payments versus allocations -- as the basis for calculation of an incentive compensation disallowance. Therefore, I recommend the Commission adopt my adjustment rather than the AG/CUB/City's.

Non-Union Base Wages Adjustment

Q. Please describe ICC Staff Exhibit 15.0, Schedules 15.8 P and N, Non-Union Wages Adjustment.

A. Schedules 15.8 P and N reflect my adjustments to reduce each Company's rate base and operating expenses to reflect test year non-union base wages at a more reasonable amount in light of the current economic environment. The adjustment is the same as reflected on Schedule 1.8 P and N, pages 1 and 2, except for a correction of the calculation of accumulated deferred income taxes. My adjustment is calculated using the 2009-2013 Consumer Price Index ("CPI") inflation rate of 2.2% as forecasted by the *Survey of Professional Forecasters*[11]

[10] AG/CUB/City Ex. 1.0, p. 19
[11] ICC Staff Ex. 1.0, p. 26, lines 620-624

which I use to escalate the Companies' 2008 actual non-union base wages to determine test year non-union base wages.[12]

Q. Does the Companies' rebuttal testimony present any new evidence as to the reasonableness of the amount of non-union wage increases proposed for inclusion in rates?

A. No. The testimony merely states my proposal is "not realistic" and further describes the methodology the Companies used for their forecast. (NS-PGL Ex. JCH-1.0, pp. 9-10) The testimony does not address the multiple Commission orders I discussed that approved test year salaries and wages based upon inflation indices.[13]

Q. The Companies state that their projected annual increases were forecasted using market data provided by the World at Work 2008-2009 Salary Budget Survey and with input from Towers Perrin consultants. (NS-PGL Ex. JCH-1.0, pp. 9-10) Has World at Work issued salary surveys since the Companies developed their forecasts?

[12] Peoples Gas accepted an $86,000 reduction in non-union merit increases noted in footnote (e) of Schedule 1.8P. This amount is deducted from Schedule 15.8 P. The Companies also accepted in total $7,493,000 and $360,000 for Peoples Gas and North Shore, respectively, for reductions in Integrys Business Support ("IBS") charges. (NS-PGL Ex. SM-2.0, p. 4) Staff Schedules 15.8 P and N deduct a portion of IBS charges adjustment as to not double count the IBS non-union wage merit increases identified in discovery.

[13] ICC Staff Ex. 1.0, p. 28, lines 666-679.

A. Yes. A July 8, 2009 press release[14] from World at Work discussed the WorldatWork 36th Annual Salary Budget Survey which collected survey data in April 2009. The press release states that corporate salary budget increases have dropped to historic lows, and that at 2.2%, the 2009 increase is the smallest in the survey's history and 1.7 percentage points below the 3.9% that had been projected in the previous year's report. Finally, the press release stated that the projected budget increase for salaries for 2010 is 2.8%.

Q. The Companies state the forecasted increase amounts are prudent and reasonable, and necessary to remain competitive in the industry. (NS-PGL Ex. JCH-1.0, p. 11) Have the Companies demonstrated the increases are reasonable?

A. No. The Companies would have rates set upon increases based on a salary study conducted prior to the current economic downturn.[15] The Companies' response to the recent changes in the economy regarding its wage increases does not demonstrate reasonableness for rate setting. The Companies state they cancelled the 2008 annual merit increases but replaced it with a "general wage delayed" increase covering a 14-month

[14] July 8, 2009 World at Work Press Release http://www.worldatwork.org/waw/adimComment?id=33490&from=Compensation%20News viewed July 15, 2009.
[15] ICC Staff Ex. 1.0, p. 27, lines 642-645.

time period. (NS-PGL Ex. JCH-1.0, p. 10) The Companies have not demonstrated why a two month salary increase delay based upon pre-economic downturn data is reasonable for ratepayers to pay during this economic downturn.

Liberty Audit Adjustment

Q. Please describe Schedule 15.10 P, Liberty Audit Adjustment.

A. Schedule 15.10 P presents my adjustment to disallow test year operating expenses prohibited from rate recovery due to the Stipulation and Memorandum ("MOU") in Docket No. 06-0311. The adjustment is updated from Schedule 1.13 P, to reflect Peoples Gas' agreement that outside contractor's fees related to the Liberty Audit should be excluded from rate recovery based on the Stipulation and MOU. (NS-PGL Ex. SM-2.0, p. 4) The adjustment is also updated to reflect the Company's rebuttal distribution expenses.

Q. The Company's rebuttal testimony presents a side-by-side comparison of your direct testimony compared to the language of the Order in Docket No. 06-0311 and further charges that you have created a new standard regarding the Commission's order. (NS-PGL Ex. JFS-2.0, pp. 13-14) Did the Company's rebuttal testimony correctly characterize your direct testimony?

A. No, I am in no manner attempting to create a new standard by which to judge costs related to the Stipulation and MOU. The Company's comparison chart is incomplete. My testimony quotes Finding (11) from the order (ICC Staff Ex. 1.0, pp. 31-32, lines 735-773) just as the Company's rebuttal testimony does. (NS-PGL Ex. JFS-2.0, p. 13) I also quoted the full Finding (4).[16] The Company takes certain statements from my direct testimony out of context to imply that my adjustment is premised on the disallowance of all costs for Peoples Gas to come into compliance with the Liberty Audit findings. I did not apply such a standard and an adjustment is warranted under the Stipulation and MOU.

Q. Company witness Mr. Schott states that "the Commission's order states clearly that unrecoverable costs are those incremental costs that are solely attributable to not performing timely inspections or solely caused by violations." (NS-PGL Ex. JFS-2.0, p. 14) Do you agree with Mr. Schott's statement?

A. I agree that Mr. Schott has generally summarized the costs ordered by the Commission to be unrecoverable. The specific language from Findings and Ordering paragraph 11 of the order prohibits recovery of "costs or expenses solely attributable to Peoples Gas not performing corrosion inspections in a timely manner, as specified in paragraph 4 above, or any

[16] ICC Staff Ex. 1.0 p. 32, lines 758-773

incremental costs caused solely by violation of the Illinois Gas Pipeline Safety Act or its implementing regulations ("the Act") discovered by the Commission's consultant retained pursuant to the Memorandum of Understanding, and which are over and above the prudent and reasonable costs necessary to comply with the Act."

Q. The Company states that "Liberty Consulting has not identified any violations of the Illinois Gas Pipeline Safety Act ("the Act") or its implementing regulations as a result of their investigation of Peoples Gas' pipeline safety practices. Therefore, no incremental costs have been incurred above prudent and reasonable costs necessary to comply with the Act." (NS-PGL Ex. ED-2.0, p. 7) Please respond.

A. Staff witness Mr. Burk in ICC Staff Exhibit 23.0 discusses the Liberty Audit with respect to its findings and identifies a number of code violations discovered by the Liberty Audit. Therefore, the premise for the Company's statement above is unsustainable.

Q. Company witness Mr. Schott similarly states that "[b]ased on the rebuttal testimony of Mr. Doerk, there have been no known non-performance or violations since the date of that Order, therefore no such incremental costs have been incurred. It would have been a waste of resources to develop a tracking mechanism for such costs where no such costs existed." (NS-PGL Ex. JFS-2.0, p. 14) Please respond.

A. First, with respect to "non-performance", it has already been determined in Docket 06-0311 that Peoples Gas failed to follow cathodic protection inspection and remediation requirements in a timely manner:

> (4) as acknowledged by Peoples Gas in the Stipulation, and as supported by the evidence, Peoples Gas was not in compliance with applicable federal and state pipeline safety regulations -- viz., 49 CFR §192.13(c) and 49 CFR §192.465(a) and (d), adopted by the Commission at 83 Ill. Admin. Code 590 pursuant to Section 3 of the Illinois Gas Pipeline Safety Act (220 ILCS 20/3) -- respecting cathodic protection inspection and remediation and the requirement to maintain and follow procedures and programs, by being late in conducting corrosion testing on certain service pipes and main segments that were due for inspection before and during 2003 and 2004, and by failing to perform corrective action during 2004 and 2005 at test points on certain service pipes and main segments found to be out of compliance during in 2003 and 2004; (*Illinois Commerce Comm'n v. The Peoples Gas Light & Coke Co.*, Ill. C.C. Docket No. 06-0311, p. 8 (Order, Dec. 20, 2006) ("06-0311 Order"))

The 06-0311 Order prohibits Peoples Gas from seeking recovery of "costs or expenses solely attributable to" these violations. The assertion that there have been no incremental costs from "non-performance" because there has allegedly been "no known non-performance … since the date of that Order" is illogical. The 06-0311 Order clearly prohibits recovery of costs or expenses incurred solely as a result of Peoples Gas' non-performance before entry of the order. Peoples Gas cannot credibly dispute that it incurred costs or expenses after the date of the 06-0311 Order to perform cathodic protection inspection and remediation requirements related to its pre-order violations. The question is whether and to what extent those costs or expenses were solely attributable to the earlier non-performance. This task could have been relatively easy and straight-forward if Peoples Gas had implemented a tracking system as ordered by the Commission. While Staff cannot directly calculate the amount of costs or expenses solely attributable to Peoples Gas' pre-order non- performance because of Peoples Gas' failure to track, Staff is confident that costs or expense for which recovery is prohibited did occur and are reflected in the test year.

As Staff witness Darin Burk explains in his rebuttal testimony (ICC Staff Ex. 23.0, pp. 8-10), Peoples Gas' non-compliance resulted in a backlog of required pending corrective actions and Peoples Gas hired contractors to perform troubleshooting and perform corrective actions in 2008. The 2010 future test year costs utilized in this case are based on extrapolations and escalations of 2008 costs. The additional costs incurred in 2008 to eliminate the backlog (in comparison to the costs that would have been incurred in 2008 without the prior violations) are costs for which recovery is prohibited under the 06-0311 Order. I also note that this is only one example of an additional cost attributable to Peoples Gas' pre-order violations. Other examples of additional costs attributable solely to the violations would be costs for re-performing work improperly performed the first time or any increased costs of performing work in 2008 versus the earlier period when it should have been performed.

Second, as noted above and explained in more detail in the testimony of Staff witness Darin Burk (ICC Staff Ex. 23.0), violations of the Pipeline Safety Act and its implementing regulations were discovered by the Commission's consultant. Once again, costs to remedy those violations should have been tracked by the Company pursuant to the 06-0311 Order so that incremental costs caused solely by those violations could be identified. Because of the Company's failure to implement a tracking mechanism, no direct measurement of such incremental costs can be made.

Finally, since it is clear as explained above that the Company incurred and seeks recovery of costs that fit within the recovery prohibition from the 06-0311 Order, Mr. Schott's assertion that "[i]t would have been a waste of resources to develop a tracking mechanism for such costs where no such costs existed" is completely erroneous. The Company's decision to not track these costs is contrary to the Commission's order, and any adverse consequences from that decision should be borne by the Company and not ratepayers.

Q. Company witness Mr. Schott also contends that your adjustment is "against public policy" by "[n]ot allowing recovery of costs to 'come into compliance.'" (NS-PGL Ex. JFS-2.0, p. 14) How do you respond?

A. First, as explained above, Mr. Schott has mischaracterized my testimony. I do not recommend disallowance of all costs to "come into compliance." Rather, I recommend disallowance of costs or expenses solely attributable to the cathodic inspection requirement violations specified in the 06-0311 Order and any incremental costs caused solely by violation of the Act or its implementing regulations discovered by the Commission's consultant. Second, the Commission's 06-0311 Order and my proposed adjustment are consistent with public policy. If a utility violates applicable statutes or rules that result in that utility incurring more costs than it would have otherwise incurred without those violations, even if those additional costs are to come into compliance, then ratepayers should not bear the additional costs resulting from the utility's violations. To allow otherwise would essentially reward or condone the utility's violations and would not be just and reasonable. In analyzing whether costs have been prudently incurred Staff not only reviews the price paid for the goods or services, but also analyzes the reason or reasons for the purchase of the goods or services. If an imprudent or improper action is what caused a cost to be incurred, then that cost is not a prudently incurred cost even if the price paid for the good or service is otherwise reasonable. Here, additional costs resulting from Company's violations are not prudently incurred costs, and the 06-0311 Order and my proposed disallowance are proper and consistent with public policy.

Q. The Company claims that your adjustment is arbitrary. (NS-PGL Ex. JFS-2.0, p. 15) Please respond.

A. Since the Company did not operate the required internal tracking mechanism to account for the incremental costs arising from the Stipulation and MOU, it was necessary for my adjustment to be based upon an estimate. The calculation of my adjustment considered the timing of the work supporting the audit, issuance of the report, implementation of corrective actions (many still in progress), and timing of the test year.[17] My understanding of the Uniform System of Accounts for Gas Utilities Operating in Illinois (83 Ill. Adm. Code 505) and the corrective actions necessary regarding the violations identified in the 06-0311 Order and the Liberty Audit is that the distribution expenses would contain most if not all of the costs at issue.

[17] ICC Staff Ex. 1.0, p. 34, lines 819-825

My direct testimony described the development of my disallowance to the test year based upon 6 months actual and 6 months forecast of 2008 costs. Much of the work associated with the audit was performed in 2008, and the audit report was issued in August 2008. In addition, as explained above, other actions to address the violations identified in the 06-0311 Order occurred in 2008. Test year expenses were developed by escalating 2008 expenses 2% for 2009 and another 1.8% for 2010.[18] For example, for every $1 million in 2008 charges, $1.038 million is included in the test year, or a cumulative 3.8% increase. Therefore, my 5.0% reduction of costs disallows the 3.8% increase due to inflation of the distribution expenses from 2008 plus 1.2% (5.0% less 3.8%) for corrective actions not allowable for cost recovery under the Stipulation and MOU, such as the fees from the Liberty Consulting Group and Huron Consulting Group. (NS-PGL Ex. SM-2.0, p. 4) While I am unable to calculate a precise disallowance given the Company's failure to implement a tracking mechanism, it is clear that significant work was performed in 2008 relative to the violations identified in the 06-0311 Order and discovered by the Commission's consultant. While I do not know the exact amount of costs or expenses incurred in this regard or the exact amount of those costs or expenses representing additional costs that would not have otherwise been incurred, 5% of the cost category including all such costs is a

[18] ICC Staff Ex. 1.0, p. 35, footnote 6

reasonable estimate in my opinion given the information available to me and the Commission.

Q. The Company presents an analogy concerning a trucking company and concludes that, "Incremental costs incurred **as a result of** violations should not be recoverable. Costs incurred **to avoid** violations should be recoverable." (NS-PGL Ex. JFS-2.0, p. 15, lines 258-267, Emphasis in original) Do you agree with the Company?

A. Speaking hypothetically here since no actual Company records are available to review, I agree that incremental costs incurred as a result of violations should not be recoverable in rates. However, the Company may have incurred two, three, or four times the normal test-year level of expense amount in order to avoid a violation. I do not believe such escalated costs should be recoverable simply because they were incurred to avoid violations. The prudence and reasonableness of the costs need to be considered.

<u>Adjustment to Future Test Year Employee Headcount</u>

Q. Have you reviewed the adjustment of AG/CUB/City witness Mr. Effron's adjustments to reduce test year headcount from 1,139 to 1,080 for

Peoples Gas and from 170 to 167 employees for North Shore? (AG/CUB/City Exhibits 1.0, 1.1, 1.2, Schedules C-2.1)

A. Yes. In regard to the adjustment to headcount for Peoples Gas, I agree with the position of Peoples Gas that its increased forecast headcount is designed to address specific Liberty Audit recommendations. (NS-PGL Ex. ED-2.0, pp. 6-7) Nothing has come to my attention to dispute the Company's contention that it will fulfill this obligation; therefore, I cannot support the AG/CUB/City headcount adjustment.

In regard to the adjustment of headcount for North Shore, I am not aware of any response from the Company other than simply not reflecting the adjustment in its rebuttal schedules; therefore, I have no opinion on whether it should be adopted.

<u>Staff Recommendations Regarding Peoples Gas' Infrastructure Cost Recovery Rider</u>

Q. Has Peoples Gas accepted any of your eleven proposed recommendations to its Infrastructure Cost Recovery ("ICR") Rider?

A. Yes. Attachment G reflects Rider ICR with the changes accepted by the Company in its rebuttal testimony (Company response to Staff Data Request DLH-23.04). Specifically, it adopts my first, second, fourth, fifth, sixth, seventh, and eighth recommendations.

Q. Have you reconsidered any of your Rider ICR recommendations?

A. Yes. Regarding my third recommendation that the Company's tariff be effective no sooner than sixty days after the date of the Final Order in this proceeding, I agree with Peoples Gas that since many of the proposed revisions to Rider ICR are now agreed upon and provided in Attachment G, that Staff would not need 60 days to review the final tariff. Further, upon advice of counsel, I understand that Senate Bill 1918 may preclude my recommendation to extend the compliance review period. Therefore, I withdraw my third recommendation.

Regarding my tenth recommendation that all cost savings resulting from the Company moving inside meters to outside of the building be netted against the costs of installing such meters, the Company's testimony estimates that only about 30,000 of 830,000 active accounts do not have automated meter reading ("AMR"). (NS-PGL Ex. ED-2.0, p. 7) The Company also clarified in its responses to Staff Data Requests DLH-24.01 and DLH-24.02 that most of its inside meters are already equipped with AMR capability. Since most of Peoples Gas' indoor meters are read via mobile AMR, any additional meter reading cost savings attributed to moving meters outdoors would be very small, and tracking such savings through Rider ICR would be overly complex in comparison to the savings tracked. Therefore, I withdraw my tenth recommendation.

Q. Did the Company agree with your ninth recommendation that no charges under Rider ICR be made until the Company's plan for its proposed accelerated infrastructure replacement program, as recommended by Staff witness Stoller in Staff Ex. 14.0, is approved by the Commission?

A. No. The Company opposes Staff witness Stoller's recommendation that the Commission must first approve the Company's accelerated infrastructure replacement plan. Based upon this position, the Company opposes my recommendation as well. (NS-PGL Ex. VG-2.0, p.53) However, should the Commission agree with Mr. Stoller that the Commission must first approve the Company's accelerated infrastructure replacement plan, the Company should not be permitted to collect charges under Rider ICR for such plan until approved by the Commission.

Q. Did Peoples Gas agree with your eleventh recommendation that the actual savings factor ("ActSav") be updated at least every three years?

A. The Company agreed that a triennial update of the factor is sufficient but disagrees to the proposed tariff language allowing updates "sooner if demonstrated to be necessary by the Company or any other party." (NS-PGL Ex. VG-2.0, p. 53, lines 1173-1180) The Company argues that if the Commission wishes to review the factor more frequently, the Commission could initiate a proceeding to do so. *Id.* The Company does not dispute the Commission's authority to review the factor more frequently, and the revised tariff language provides the same opportunity to update the factor with a showing of evidence as would be necessary in a separate proceeding. Including my proposed language in the tariff makes clear that this factor may need to be updated if circumstances warrant. To require a separate proceeding places an unnecessary burden on the Commission and other parties seeking an update.

<u>Staff Recommendation Regarding North Shore and Peoples Gas' Volume Balancing Adjustment Rider</u>

Q. Have the Companies provided the proposed new monthly rate case margins which will be effective in their Volume Balancing Adjustment ("VBA") Rider based on their rebuttal case?

A. No, the Companies stated they may be able to provide updates as the case progresses provided that sufficient information is available to develop charges that would arise from such updates. The Companies also stated they will provide final Rider VBA rate case margins, based on the approved distribution charges, to the Commission with their compliance filing. (NS-PGL Ex. VG-2.0. p. 5, lines 91-93) In their response to Staff Data Request DLH-23.01, the Companies provided their new monthly VBA rate case margins based on their rebuttal revenue requirements. For purposes of a complete record, I have attached these responses to my testimony as Attachment H.

Q. Did the Companies agree to prepare, rather than Staff, the annual report on the Companies' rates of return and the effect on that return of Rider VBA, as you recommended in direct testimony?

A. Yes. (NS-PGL Ex. VG-2.0, pp. 53-54, lines 1182-1186)

<u>Conclusion</u>

Q. Does this conclude your prepared rebuttal testimony?

A. Yes, it does.

Docket Nos. 09-0166/09-0167
Consolidated
ICC Staff Ex. 15.0
Schedule 15.1 P

The Peoples Gas Light and Coke Company
Statement of Operating Income with Adjustments
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Jurisdictional Operating Income (NS-PGL Ex. SM-2.1P, col. E)	Staff Adjustments (Sch 15. 2 P)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (NS-PGL Ex. SM-2.1P, col. H)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ 441,232	$ -	$ 441,232	$ 119,312	$ 3,054	$ 563,598	$ (74,124)	$ 489,474
2	PGA Revenues	-	-	-	-	-	-	-	-
3	Coal Tar Revenues	-	-	-	-	-	-	-	-
4	Other Revenues	20,902	-	20,902	3,053	-	23,955	-	23,955
5	Total Operating Revenue	462,134	-	462,134	122,365	3,054	587,553	(74,124)	513,429
6	Uncollectibles Expense	29,409	(1,915)	27,494	3,108	-	30,602	(1,883)	28,719
7	Cost of Gas	-	-	-	-	-	-	-	-
8	Other Production	-	-	-	-	-	-	-	-
9	Distribution	99,211	(6,031)	93,180	-	-	93,180	-	93,180
10	Customer Accounts	31,610	2,001	33,611	-	-	33,611	-	33,611
11	Customer Service and Informational Services	3,711	1,071	4,782	-	-	4,782	-	4,782
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	126,703	(13,627)	113,076	-	-	113,076	-	113,076
14	Depreciation and Amortization	81,498	(137)	81,361	-	-	81,361	-	81,361
15	Storage	10,499	(484)	10,015	-	-	10,015	-	10,015
16	Transmission	4,356	(1,667)	2,689	-	-	2,689	-	2,689
17	Taxes Other than Income	21,776	(1,133)	20,643	-	-	20,643	-	20,643
18	Total Operating Expense								
19	Before Income Taxes	408,773	(21,922)	386,851	3,108	-	389,959	(1,883)	388,076
20	State Income Tax	618	2,111	2,729	8,706	-	11,435	(5,274)	6,161
21	Federal Income Tax	9,267	9,375	18,642	38,692	1	57,335	(23,439)	33,896
22	Deferred Taxes and ITCs Net	(5,059)	-	(5,059)	-	-	(5,059)	-	(5,059)
23	Total Operating Expenses	413,599	(10,436)	403,163	50,506	1	453,670	(30,596)	423,074
24	NET OPERATING INCOME	$ 48,535	$ 10,436	$ 58,971	$ 71,859	$ 3,053	$ 133,883	$ (43,528)	$ 90,355
25	Staff Rate Base (Schedule 15.3 P, column (d), line 23)								$ 1,165,860
26	Staff Overall Rate of Return (ICC Staff Exhibit 22.0, Schedule 22.1)								7.75%
27	Revenue Change (column (i), line 5 minus column (d), line 5)								$ 51,295
28	Percentage Change (column (i), line 27 divided by column (d), line 5)								11.10%

The Peoples Gas Light and Coke Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Interest Synchronization (Sch.15.5 P)	Incentive Compensation (Sch. 15.7 P)	Non-Union Base Wages (Sch. 15.8 P)	Invested Capital Taxes (Sch. 15.9 P)	Liberty Audit (Sch. 15.10 P)	Merger Costs & Savings (Sch. 16.2 P)	Injuries & Damages (Sch. 17.2 P)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	PGA Revenues	-	-	-	-	-	-	-	-
3	Coal Tar Revenues	-	-	-	-	-	-	-	-
4	Other Revenues	-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectibles Expense	-	-	-	-	-	-	-	-
7	Cost of Gas	-	-	-	-	-	-	-	-
8	Other Production	-	-	-	-	-	-	-	-
9	Distribution	-	(954)	(98)	-	(4,961)	-	-	(6,013)
10	Customer Accounts	-	(840)	2,841	-	-	-	-	2,001
11	Customer Service and Informational Services	-	(30)	1,451	-	-	-	-	1,421
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	-	(5,802)	(3,367)	-	-	(105)	(864)	(10,138)
14	Depreciation and Amortization	-	(15)	(29)	-	-	-	-	(44)
15	Storage	-	(255)	(49)	-	-	-	-	(304)
16	Transmission	-	(126)	(1,517)	-	-	-	-	(1,643)
17	Taxes Other than Income	-	(664)	(145)	(324)	-	-	-	(1,133)
18	Total Operating Expense								
19	Before Income Taxes	-	(8,686)	(914)	(324)	(4,961)	(105)	(864)	(15,853)
20	State Income Tax	509	634	67	24	362	8	63	1,667
21	Federal Income Tax	2,264	2,818	296	105	1,609	34	280	7,406
22	Deferred Taxes and ITCs Ne	-	-	-	-	-	-	-	-
23	Total Operating Expenses	2,773	(5,234)	(551)	(195)	(2,990)	(63)	(521)	(6,780)
24	NET OPERATING INCOME	$ (2,773)	$ 5,234	$ 551	$ 195	$ 2,990	$ 63	$ 521	$ 6,780

The Peoples Gas Light and Coke Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Non-Recoverable Cushion Gas (Staff Ex. 27.0 & Sch. 18.2 P)	Gathering System Phase 2 (Staff Ex. 27.0 & Sch. 18.3 P)	Gathering System Pigging (Staff Ex. 27.0 & Sch. 18.4 P)	Uncollectibles Expense (Sch. 19.1 P)	Advertising Expense (Sch. 20.1 P)	Company Use Gas (Sch. 27.4 P)	Subtotal Operating Statement Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Base Rate Revenues	$ -	$ -	$ -				$ -	$ -
2	PGA Revenues	-	-	-	-	-	-	-	-
3	Coal Tar Revenues	-	-	-	-	-	-	-	-
4	Other Revenues	-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectibles Expense	-	-	-	-	(1,915)	-	-	(1,915)
7	Cost of Gas	-	-	-	-	-	-	-	-
8	Other Production	-	-	-	-	-	-	-	-
9	Distribution	(6,013)	-	-	-	-	-	(18)	(6,031)
10	Customer Accounts	2,001	-	-	-	-	-	-	2,001
11	Customer Service and Informational Services	1,421	-	-	-	-	(350)	-	1,071
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	(10,138)	-	-	-	-	-	-	(10,138)
14	Depreciation and Amortization	(44)	(9)	(71)	(13)	-	-	-	(137)
15	Storage	(304)	-	-	-	-	-	(180)	(484)
16	Transmission	(1,643)	-	-	-	-	-	(24)	(1,667)
17	Taxes Other than Income	(1,133)	-	-	-	-	-	-	(1,133)
18	Total Operating Expense								
19	Before Income Taxes	(15,853)	(9)	(71)	(13)	(1,915)	(350)	(222)	(18,433)
20	State Income Tax	1,667	1	5	1	140	26	16	1,856
21	Federal Income Tax	7,406	3	23	4	621	114	72	8,243
22	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
23	Total Operating Expenses	(6,780)	(5)	(43)	(8)	(1,154)	(210)	(134)	(8,334)
24	NET OPERATING INCOME	$ 6,780	$ 5	$ 43	$ 8	$ 1,154	$ 210	$ 134	$ 8,334

The Peoples Gas Light and Coke Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Regulatory Asset Correction (Staff Ex. 16.0)	(Source)	(Source)	(Source)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	PGA Revenues	-	-	-	-	-	-	-	-
3	Coal Tar Revenues	-	-	-	-	-	-	-	-
4	Other Revenues	-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectibles Expense	(1,915)	-	-	-	-	-	-	(1,915)
7	Cost of Gas	-	-	-	-	-	-	-	-
8	Other Production	-	-	-	-	-	-	-	-
9	Distribution	(6,031)	-	-	-	-	-	-	(6,031)
10	Customer Accounts	2,001	-	-	-	-	-	-	2,001
11	Customer Service and Informational Services	1,071	-	-	-	-	-	-	1,071
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	(10,138)	(3,489)	-	-	-	-	-	(13,627)
14	Depreciation and Amortization	(137)	-	-	-	-	-	-	(137)
15	Storage	(484)	-	-	-	-	-	-	(484)
16	Transmission	(1,667)	-	-	-	-	-	-	(1,667)
17	Taxes Other than Income	(1,133)	-	-	-	-	-	-	(1,133)
18	Total Operating Expense								
19	Before Income Taxes	(18,433)	(3,489)	-	-	-	-	-	(21,922)
20	State Income Tax	1,856	255	-	-	-	-	-	2,111
21	Federal Income Tax	8,243	1,132	-	-	-	-	-	9,375
22	Deferred Taxes and ITCs Ne	-	-	-	-	-	-	-	-
23	Total Operating Expenses	(8,334)	(2,102)	-	-	-	-	-	(10,436)
24	NET OPERATING INCOME	$ 8,334	$ 2,102	$ -	$ -	$ -	$ -	$ -	$ 10,436

The Peoples Gas Light and Coke Company
Rate Base
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Jurisdictional Rate Base (NS-PGL Ex. JH-2.1P) col. F)	Staff Adjustments (Sch.15.4 P)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Utility Plant	$ 2,577,615	$ (5,547)	$ 2,572,068
2	Accumulated Provision for Depreciation and Amortization	(1,068,305)	233	(1,068,072)
3		-	-	-
4	Net Plant	$ 1,509,310	$ (5,314)	$ 1,503,996
5	Additions to Rate Base:			
6	Materials and Supplies	9,871	-	9,871
7	Cash Working Capital	34,325	(31,184)	3,141
8	Gas in Storage	49,440	(663)	48,777
9	Budget Plan Balances	12,605	-	12,605
10	Retirement Benefits, Net	67,827	(155,496)	(87,669)
11		-	-	-
12	Deductions From Rate Base:			
13	Accumulated Deferred Income Taxes	(343,851)	59,777	(284,074)
14	Pre-1971 Investment Tax Credits	-	-	-
15	Reserve for Injuries and Damages	(8,307)	-	(8,307)
16	Customer Advances for Construction	(392)	-	(392)
17	Customer Deposits	(32,088)	-	(32,088)
18		-	-	-
19		-	-	-
20		-	-	-
21		-	-	-
22		-	-	-
23	Rate Base	$ 1,298,740	$ (132,880)	$ 1,165,860

The Peoples Gas Light and Coke Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Incentive Compensation (Sch. 15.7 P)	Non-Union Base Wages (Sch. 15.8 P)	Pension Asset (Sch. 16.1 P)	Cash Working Capital (Sch. 17.1 P)	Recoverable Cushion Gas (Staff Ex. 27.0 & Sch. 18.1 P)	Non-Recoverable Cushion Gas (Staff Ex. 27.0 & Sch. 18.2 P)	Gathering System Phase 2 (Staff Ex. 27.0 & Sch. 18.3 P)	Subtotal Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Utility Plant	$ (675)	$ (1,150)	$ -	$ -	$ (18)	$ (354)	$ (2,850)	$ (5,047)
2	Accumulated Provision for Depreciation and Amortization	99	29	-	-	-	9	71	208
3		-	-	-	-	-	-	-	-
4	Net Plant	$ (576)	$ (1,121)	$ -	$ -	$ (18)	$ (345)	$ (2,779)	$ (4,839)
5	Additions to Rate Base:								
6	Materials and Supplies	-	-	-	-	-	-	-	-
7	Cash Working Capital	-	-	-	(31,184)	-	-	-	(31,184)
8	Gas in Storage	-	-	-	-	-	-	-	-
9	Budget Plan Balances	-	-	-	-	-	-	-	-
10	Retirement Benefits, Net	-	-	(155,496)	-	-	-	-	(155,496)
11		-	-	-	-	-	-	-	-
12	Deductions From Rate Base:	-	-	-	-	-	-	-	-
13	Accumulated Deferred Income Taxes	3	5	59,731	-	-	3	23	59,765
14	Pre-1971 Investment Tax Credits	-	-	-	-	-	-	-	-
15	Reserve for Injuries and Damages	-	-	-	-	-	-	-	-
16	Customer Advances for Construction	-	-	-	-	-	-	-	-
17	Customer Deposits	-	-	-	-	-	-	-	-
18		-	-	-	-	-	-	-	-
19		-	-	-	-	-	-	-	-
20		-	-	-	-	-	-	-	-
21		-	-	-	-	-	-	-	-
22		-	-	-	-	-	-	-	-
23	Rate Base	$ (573)	$ (1,116)	$ (95,765)	$ (31,184)	$ (18)	$ (342)	$ (2,756)	$ (131,754)

The Peoples Gas Light and Coke Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Subtotal Rate Base Adjustments	Gathering System Pigging (Staff Ex. 27.0 & Sch. 18.4 P)	Gas in Storage (Sch. 27.3 P)	(Source)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Gross Utility Plant	$ (5,047)	$ (500)	$ -	$ -	$ -	$ -	$ -	$ (5,547)
2	Accumulated Provision for Depreciation and Amortization	208	25	-	-	-	-	-	233
3	-	-	-	-	-	-	-	-	-
4	Net Plant	(4,839)	(475)	-	-	-	-	-	(5,314)
	-								
5	Additions to Rate Base:								-
6	Materials and Supplies	-	-	-	-	-	-	-	-
7	Cash Working Capital	(31,184)	-	-	-	-	-	-	(31,184)
8	Gas in Storage	-	-	(663)	-	-	-	-	(663)
9	Budget Plan Balances	-	-	-	-	-	-	-	-
10	Retirement Benefits, Net	(155,496)	-	-	-	-	-	-	(155,496)
11	-	-	-	-	-	-	-	-	-
12	Deductions From Rate Base:	-	-	-	-	-	-	-	-
13	Accumulated Deferred Income Taxes	59,765	12	-	-	-	-	-	59,777
14	Pre-1971 Investment Tax Credits	-	-	-	-	-	-	-	-
15	Reserve for Injuries and Damages	-	-	-	-	-	-	-	-
16	Customer Advances for Construction	-	-	-	-	-	-	-	-
17	Customer Deposits	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-
20	-	-	-	-	-	-	-	-	-
21	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
23	Rate Base	$ (131,754)	$ (463)	$ (663)	$ -	$ -	$ -	$ -	$ (132,880)

The Peoples Gas Light and Coke Company

Interest Synchronization Adjustment

For the Test Year Ending December 31, 2010

(In Thousands)

Line No.	Description	Amount
	(a)	(b)
1	Rate Base	$ 1,165,860 (1)
2	Weighted Cost of Debt	2.32% (2)
3	Synchronized Interest Per Staff (Line 1 x Line 2)	$ 27,048
4	Company Interest Expense	34,027 (3)
5	Increase (Decrease) in Interest Expense	$ (6,979)
6	Increase (Decrease) in State Income Tax Expense	
7	at 7.300%	$ 509
8	Increase (Decrease) in Federal Income Tax Expense	
9	at 35.000%	$ 2,264

(1) Source: Schedule 15.3 P, column (d), line 23
(2) Source: ICC Staff Exhibit 22.0, Schedule 22.1
(3) Source: NS-PGL Ex. SM-2.9P

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Schedule 15.6 P

The Peoples Gas Light and Coke Company

Gross Revenue Conversion Factor

For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	1.000000
2	Uncollectibles	2.5400%	0.025400	
3	State Taxable Income		0.974600	
4	State Income Tax	7.3000%	0.071146	0.073000
5	Federal Taxable Income		0.903454	0.927000
6	Federal Income Tax	35.0000%	0.316209	0.324450
7	Operating Income		0.587245	0.602550
8	Gross Revenue Conversion Factor Per Staff (Line 1 / Line 7)		1.702867	1.659613

The Peoples Gas Light and Coke Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description (a)	Amount (b)	Source (c)
1	Summary		
2	Total Storage Adjustment per Staff	$ (255)	Sch. 15.7 P, p. 3 , line 2, cols. (c), (e), (f), & (h)
3	Total Storage Adjustment per Company	-	
4	Total Staff Proposed Adjustment to Storage Expense	$ (255)	
5	Total Transmission Adjustment per Staff	$ (126)	Sch. 15.7 P, p. 3 , line 3, cols. (c), (e), (f), & (h)
6	Total Transmission Adjustment per Company	-	
7	Total Staff Proposed Adjustment to Transmission Expense	$ (126)	
8	Total Customer Accounts Adjustment per Staff	$ (840)	Sch. 15.7 P, p. 3 , line 5, cols. (c), (e), (f), & (h)
9	Total Customer Accounts Adjustment per Company	-	
10	Total Staff Proposed Adjustment to Customer Accounts Exp.	$ (840)	
11	Total Distribution Adjustment per Staff	$ (954)	Sch. 15.7 P, p. 3 , line 4, cols. (c), (e), (f), & (h)
12	Total Distribution Adjustment per Company	-	
13	Total Staff Proposed Adjustment to Distribution Expense	$ (954)	
14	Total Cust. Serv. and Info. Serv. Adjustment per Staff	$ (30)	Sch. 15.7 P, p. 3 , line 4, cols. (c), (e), (f), & (h)
15	Total Cust. Serv. and Info. Serv. Adjustment per Company	-	
16	Total Staff Proposed Adjustment to Cust.& Info. Services Exp.	$ (30)	
17	Total Admin. & General Adjustment per Staff	$ (5,802)	Sch. 15.7 P, p. 2 , lines 4, 7, 8, and 9 + Sch. 15.7 P, p. 3 , line 7, cols. (c), (e), (f), & (h) + Sch. 1.7 P, p. 4 , lines 4, 7, and 10
18	Total Admin. & General Adjustment per Company	-	
19	Total Staff Proposed Adjustment to Admin. & General Expense	$ (5,802)	
20	Total Capitalized Adjustment amount per Staff	$ (675)	Sch. 15.7 P, p. 3 , line 8, cols. (c), (e), (f), & (h) + Sch. 1.7 P, p. 5 , line 4
21	Total Capitalized Adjustment amount per Company	-	
22	Total Staff Proposed Adjustment to Rate Base	$ (675)	
23	Total Payroll Taxes Adjustment per Staff	$ (664)	(Sum of Lines 4, 7, 10, 13, 16, 19 and 22) x 7.65%
24	Total Payroll Taxes Adjustment per Company	-	
25	Total Staff Proposed Adjustment to Taxes Other Than Income	$ (664)	
26	Depreciation Expense Adjustment per Staff	$ (15)	Sch. 15.7 P, p. 3 , line 8, cols. (c), (e), (f), & (h) x Composite rate of 2.5% per DLH-11.01+ Sch. 15.7 P, p. 5 , line 10
27	Depreciation Expense Adjustment per Company	-	
28	Staff Proposed Adjustment to Depreciation Expense	$ (15)	
29	Accumulated Depreciation Adjustment per Staff	$ 99	Sch. 15.7 P, p. 1 , line 28 x -1 + Sch. 15.7 P, p. 5 , line 7
30	Accumulated Depreciation Adjustment per Company	-	
31	Staff Proposed Adjustment to Accumulated Depreciation	$ 99	
32	Accumulated Deferred Income Taxes Adjustment per Staff	$ 3	Company response to Staff Data Request DLH-23.03
33	Accumulated Deferred Income Taxes Adjustment per Company	-	
34	Staff Proposed Adjustment to Accum. Def. Income Taxes	$ 3	

The Peoples Gas Light and Coke Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description		Amount	Source
	(a)		(b)	(c)
1	Executive Plan			
2	Administrative and General Total Cost	$	816	Company Response to DLH-8.02, p. 2 and DLH-11.04 Attach. B Revised
3	Financial Weighting		70%	Company Response to DLH-8.04
4	Executive Plan Financial Goals Cost	$	(571)	Line 2 x line 3 x -1
5	Non-Financial Weighting		30%	Company Response to DLH-8.04
6	Executive Plan Non-Financial Goals Cost	$	245	Line 5 x line 2
7	Performance Goals Unlikely to be Achieved at 20% of line 6	$	(49)	See Sch. 1.7 P, p, 3, col. (e) x -1
8	Performance Goals Based on Non-PGL Achievements	$	(8)	Lline 7 x line 15
9	Performance Goals Based on IEG Net Income	$	(94)	(Line 6 + line 7 + line 8) x -50%; Company Response to DLH-21.01
10	Allocation for line 8 calculated based upon the percentage of IBS Gas Services and IBS Corp. Services & SSO to total Peoples Gas:			
11	IBS Gas Services		31	Company Response to DLH-13.02
12	IBS Corp. Services & SSO		107	Company Response to DLH-13.03
13	Sub-total		138	
14	Total Exec PGL Charges	$	816	Col. (b) line 2
15	Calculated Allocation percent		17%	Line 14 / line 15

The Peoples Gas Light and Coke Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Total Amount	Financial Goals	Subtotal	Performance Goals Unlikely to be Achieved	Perform. Goals Based on Non-PGL Achievements	Subtotal	Remainder of Perf. Goals Reduced if IEG (parent) Net Income Not Reached
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			(b) x -50%	(b) + (c)	(d) x -20%	(d) x- 74%	(d) + (e) + (f)	(g) x -50%
1	Non-Executive Plan							
2	Storage	$ 259	$ (129)	$ 130	$ (26)	$ (96)	$ 8	$ (4)
3	Transmission	127	(64)	63	(13)	(47)	3	(2)
4	Distribution	968	(484)	484	(97)	(359)	28	(14)
5	Customer Accounts	853	(426)	427	(85)	(316)	26	(13)
6	Cust. Serv. & Info. Serv.	30	(15)	15	(3)	(11)	1	(1)
7	Admin. and General	2,043	(1,022)	1,021	(204)	(756)	61	(31)
8	Gross Plant	517	(258)	259	(52)	(192)	15	(7)

Sources by Column:
(b) Company Response to DLH-8.02 pp. 1-2
(c) Weighted at 50% per Response to DLH-8.04
(e) 10% each for Reduction in Leaks and OSHA recordable incidents goals
(f) Allocation calculated based upon the percentage of IBS Gas Services and IBS Corp. Services & SSO to total Peoples Gas:

IBS Gas Services	1,142	Company Response to DLH-13.02
IBS Corp. Services & SSO	2,431	Company Response to DLH-13.03
Sub-total	3,573	
Total Non-Exec PGL Charges	$ 4,798	Col. (b) sum of line 2 through 8
Calculated Allocation percent	74%	

(h) Source: Company Response to AG-3.40

The Peoples Gas Light and Coke Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description (a)	Amount (b)	Source (c)
1	Stock Plans		
2	Integrys Restricted Stock Unit Award per Staff	$ -	
3	Integrys Restricted Stock Unit Award per Company	1,280	(1), (2)
4	Staff Proposed Adjustment to Admin. & General Exp.	$ (1,280)	Line 2 - line 3
5	Integrys Performance Stock Right Agreement per Staff	$ -	
6	Integrys Performance Stock Right Agreement per Company	1,068	(1), (2)
7	Staff Proposed Adjustment to Admin. & General Exp.	$ (1,068)	Line 5 - line 6
8	Integrys NonQualified Option Agreement per Staff	$ -	
9	Integrys NonQualified Option Agreement per Company	719	(1)
10	Staff Proposed Adjustment to Admin. & General Exp.	$ (719)	Line 8 - line 9

(1) Source: Company Responses to Staff Data Requests DLH-8.02 and DLH-11.04
(2) $1,473 from DLH-11.04 Attach. B Revised for Restricted Stock & Performance Stock split 50/50

The Peoples Gas Light and Coke Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description (a)	Amount (b)	Source (c)
1	Prior Plant Disallowance		
2	Adjustment for Prior Disallowed Plant per Staff	$ (166)	Company Response to DLH-11.01
3	Adjustment for Prior Disallowed Plant per Company	-	Response to DLH-11.01
4	Staff Proposed Adjustment to Plant	$ (166)	Line 2 - line 3
5	Adjustment for Accum. Deprec. on Prior Disallowed Plant per Staff	$ 84	Line 13
6	Adjustment for Accum. Deprec. on Prior Disallowed Plant per Company	-	Company Response to DLH-11.01
7	Staff Proposed Adjustment to Accum Deprec.	$ 84	Line 5 - line 6
8	Adjustment for Deprec. Exp. on Prior Disallowed Plant per Staff	$ (2)	Line 15 * -1
9	Adjustment for Deprec. Exp. on Prior Disallowed Plant per Company	-	Company Response to DLH-11.01
10	Staff Proposed Adjustment to Depreciation Expense	$ (2)	Line 8 - line 9
11	Accum. Deprec. On Disallowed Plant Balance at 12/31/2009	$ 81	Company Response to DLH-11.01
12	Accum. Deprec. On Disallowed Plant Balance at 12/31/2010	86	Company Response to DLH-11.01
13	Average Balance	$ 84	(Line 11 + Line 12) / 2
14	Average Net Plant	$ 83	(Line 4 + line 13) * -1
15	Depreciation Expense	$ 2	Line 14 * Composite Rate of 2.5% per Company Response to DLH-11.01

The Peoples Gas Light and Coke Company

Non-Union Base Wages Adjustment

For the Test Year Ending December 31, 2010

(In Thousands)

Line No.	Description	Test Year Amount per Staff	Test Year Amount per Company	Subtotal	Reductions per Company	Staff Proposed Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)
1	Storage	$ 3,108	$ 3,157	$ (49)	$ -	$ (49)
2	Transmission	61	1,578	(1,517)		(1,517)
3	Distribution	13,731	13,829	(98)		(98)
4	Customer Accounts	13,847	11,006	2,841		2,841
5	Customer Services & Informational Services	1,852	401	1,451		1,451
6	Administrative & General	19,914	23,609	(3,695)	328	(3,367)
7	Construction	6,498	7,648	(1,150)		(1,150)
8	Total	$ 59,010	$ 61,228	$ (2,218)	$ 328	$ (1,890)
9	Payroll Taxes at line 8 x 7.65%					(145)
10	Depreciation Expense at line 7 x Composite rate of 2.5% per DLH-20.02					(29)
11	Accumulated Depreciation at line 7 x -1 x Composite rate of 2.5% per DLH-20.02					29
12	Company response to Staff Data Request DLH-23.03					5

Sources by Column:

(b) Source: Sch. 1.8 P, p. 2, col (d)

(c) Source: Company Response to DLH-20.01, Attach 1, col [B]

Total Other Payroll from DLH-20.01 Allocated Based on Test Year Split in DLH-2.02:		
Total Other included in Schedule B-1 per DLH-2.02	$ 7,068	80%
Total Other included in ScheduleC-1, Distribution, per DLH-2.02	1,774	20%
Total Other Payroll per DLH-2.02	$ 8,842	100%
Test Year Non-Union Base Total Other Payroll of $8,169 Allocated to Constuction at 80%	6,530	
Test Year Non-Union Base Total Other Payroll of $8,169 Allocated to Distribution at 20%	1,639	

(d) Source: Col. (b) - Col. (c)

(e) Source: Company Response to DLH-12.03

Company proposed reduction in IBS non-union wage merit increases	$ 242
Company proposed reduction in PGL non-union wage merit increases	86
Total	$ 328

(f) Source: Col. (d) + Col. (e)

The Peoples Gas Light and Coke Company
Non-Union Base Wages Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Actual 2008 Amount	Calculated 2009 Per Staff	Calculated 2010 Per Staff
	(a)	(b)	(c)	(d)
1	Storage	$ 2,976	$ 3,041	$ 3,108
2	Transmission	58	59	61
3	Distribution	13,146	13,435	13,731
4	Customer Accounts	13,257	13,549	13,847
5	Customer Services & Informational Services	1,773	1,812	1,852
6	Administrative & General	19,066	19,485	19,914
7	Construction	6,221	6,358	6,498
8	Total	$ 56,497	$ 57,740	$ 59,010

Sources by Column:

(b) Source:Company Revised Response to DLH-20.01, Attach 1, col [D]
Total Other Payroll from DLH-20.01 Allocated Based on Test Year Split in DLH-2.02:
Test Year Non-Union Base Total Other Payroll of $6,102 Allocated to Constuction at 80%
Test Year Non-Union Base Total Other Payroll of $6,102 Allocated to Distribution at 20%

(c) Source: Col. (b) x 1.022
(d) Source: Col. (c) x 1.022

The Peoples Gas Light and Coke Company

Invested Capital Taxes Adjustment

For the Test Year Ending December 31, 2010

(In Thousands)

Line No.	Description (a)	Amount (b)	Source (c)
1	Rate Base	$ 1,165,860	Staff Ex. 15.0, Schedule 15.1 P, col. i, line 25
2	Rate of Return	7.75%	Staff Ex. 15.0, Schedule 15.1 P, col. i, line 26
3	Operating Income Required	$ 90,354	Line 1 x Line 2
4	Pro forma operating income at present rates adjusted before ICT adjustment	59,295	Staff Ex. 15.0, Schedule 15.1 P, col. d line 24 - Staff Ex. 15.0, Schedule 15.2 P, page 1, col. e line 17
5	Operating Income Additional Allowed	$ 31,059	Line 3 - line 4
6	Invested Capital Tax Rate	0.80%	NS-PGL Ex. SM-2.8P
7	Incremental Invested Capital Tax Impact per Staff	$ 248	Line 5 x line 6
8	Incremental Invested Capital Tax Impact per Company	572	NS-PGL Ex. SM-2.8P
9	Staff Proposed Adjustment	$ (324)	Line 7 - line 8

The Peoples Gas Light and Coke Company

Liberty Audit Adjustment

For the Test Year Ending December 31, 2010

(In Thousands)

Line No.	Description (a)		Amount (b)	Source (c)
1	Liberty Audit Adustment -Distribution Expenses per Staff		(4,961)	Line 6
2	Liberty Audit Adustment per Company		0	
3	Total Staff Proposed Adjustment	$	(4,961)	Line 1 - line 2
4	(1) Source:			
5	Test Year Rebuttal Proposed Distribution Expense	$	99,211	NS-PGL Ex. SM-2.1P, line 8
6	5%	$	4,961	Line 5 x 5%
7	Alternative at 3.8%	$	3,770	Line 5 x 3.8%
8	Difference in Alternatives	$	1,191	Line 6 - line 7

North Shore Gas Company
Statement of Operating Income with Adjustments
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Jurisdictional Operating Income (NS-PGL Ex. SM-2.1N, col. E)	Staff Adjustments (Sch 15. 2 N)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (NS-PGL Ex. SM-2.1P, col. H)	Staff Gross Revenue Conversion Factor	Proposed Rates With Staff Adjustments (Cols. d+e+f)	Adjustment To Proposed Increase	Staff Pro Forma Proposed (Cols. g+h)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ 63,221	$ -	$ 63,221	$ 20,021	$ 163	$ 83,405	$ (6,866)	$ 76,539
2	PGA Revenues	-	-	-	-	-	-	-	-
3	Coal Tar Revenues	-	-	-	-	-	-	-	-
4	Other Revenues	2,072	-	2,072	98	-	2,170	-	2,170
5	Total Operating Revenue	65,293	-	65,293	20,119	163	85,575	(6,866)	78,709
6	Uncollectibles Expense	1,628	(97)	1,531	140	1	1,672	(48)	1,624
7	Cost of Gas	-	-	-	-	-	-	-	-
8	Other Production	350	(41)	309	-	-	309	-	309
9	Distribution	10,828	(323)	10,505	-	-	10,505	-	10,505
10	Customer Accounts	7,492	8	7,500	-	-	7,500	-	7,500
11	Customer Service and Informational Services	656	188	844	-	-	844	-	844
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	27,754	(2,309)	25,445	-	-	25,445	-	25,445
14	Depreciation	9,432	(4)	9,428	-	-	9,428	-	9,428
15	Storage	-	-	-	-	-	-	-	-
16	Transmission	425	-	425	-	-	425	-	425
17	Taxes Other than Income	3,383	(188)	3,195	-	-	3,195	-	3,195
18	Total Operating Expense								
19	Before Income Taxes	61,948	(2,766)	59,182	140	1	59,323	(48)	59,275
20	State Income Tax	(684)	204	(480)	1,452	11	983	(498)	485
21	Federal Income Tax	(4,690)	910	(3,780)	6,450	53	2,723	(2,212)	511
22	Deferred Taxes and ITCs Net	4,486	-	4,486	-	-	4,486	-	4,486
23	Total Operating Expenses	61,060	(1,652)	59,408	8,042	65	67,515	(2,758)	64,757
24	NET OPERATING INCOME	$ 4,233	$ 1,652	$ 5,885	$ 12,077	$ 98	$ 18,060	$ (4,108)	$ 13,952
25	Staff Rate Base (Schedule 15.3 N, column (d), line 23)								$ 176,706
26	Staff Overall Rate of Return (ICC Staff Exhibit 22.0, Schedule 22.1)								7.90%
27	Revenue Change (column (i), line 5 minus column (d), line 5)								$ 13,416
28	Percentage Change (column (i), line 27 divided by column (d), line 5)								20.55%

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Schedule 15.2 N, page 1 of 2

North Shore Gas Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Interest Synchronization (Sch.15.5 N)	Incentive Compensation (Sch. 15.7 N)	Non-Union Base Wages (Sch. 15.8 N)	Invested Capital Taxes (Sch. 15.9 N)	Merger Costs & Savings (Sch. 16.2 N)	Injuries & Damages (Sch. 17.2 N)	Uncollectibles Expense (Sch. 19.1 N)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	PGA Revenues	-	-	-	-	-	-	-	-
3	Coal Tar Revenues	-	-	-	-	-	-	-	-
4	Other Revenues	-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectibles Expense	-	-	-	-	-	-	(97)	(97)
7	Cost of Gas	-	-	-	-	-	-	-	-
8	Other Production	-	(28)	(13)	-	-	-	-	(41)
9	Distribution	-	(173)	(147)	-	-	-	-	(320)
10	Customer Accounts	-	(149)	157	-	-	-	-	8
11	Customer Service and Informational Services	-	(7)	280	-	-	-	-	273
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	-	(1,381)	(360)	-	(28)	(159)	-	(1,928)
14	Depreciation	-	(2)	(2)	-	-	-	-	(4)
15	Storage	-	-	-	-	-	-	-	-
16	Transmission	-	-	-	-	-	-	-	-
17	Taxes Other than Income	-	(142)	(15)	(31)	-	-	-	(188)
18	Total Operating Expense								
19	Before Income Taxes	-	(1,882)	(100)	(31)	(28)	(159)	(97)	(2,297)
20	State Income Tax	3	137	7	2	2	12	7	170
21	Federal Income Tax	12	611	32	10	9	52	31	757
22	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
23	Total Operating Expenses	15	(1,134)	(61)	(19)	(17)	(95)	(59)	(1,370)
24	NET OPERATING INCOME	$ (15)	$ 1,134	$ 61	$ 19	$ 17	$ 95	$ 59	$ 1,370

North Shore Gas Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Subtotal Operating Statement Adjustments	Advertising Expense (Sch. 20.1 N)	Company Use Gas (Sch. 27.4 N)	Franchise Gas (Sch. 27.5 N)	Regulatory Asset Correction (Staff Ex. 16.0)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Base Rate Revenues	$ -	$ -	$ -				$ -	$ -
2	PGA Revenues	-	-	-	-	-	-	-	-
3	Coal Tar Revenues	-	-	-	-	-	-	-	-
4	Other Revenues	-	-	-	-	-	-	-	-
5	Total Operating Revenue	-	-	-	-	-	-	-	-
6	Uncollectibles Expense	(97)	-	-	-	-	-	-	(97)
7	Cost of Gas	-	-	-	-	-	-	-	-
8	Other Production	(41)	-	-	-	-	-	-	(41)
9	Distribution	(320)	-	(3)	-	-	-	-	(323)
10	Customer Accounts	8	-	-	-	-	-	-	8
11	Customer Service and Informational Services	273	(85)	-	-	-	-	-	188
12	Sales	-	-	-	-	-	-	-	-
13	Administrative and General	(1,928)	-	-	(92)	(289)	-	-	(2,309)
14	Depreciation	(4)	-	-	-	-	-	-	(4)
15	Storage	-	-	-	-	-	-	-	-
16	Transmission	-	-	-	-	-	-	-	-
17	Taxes Other than Income	(188)	-	-	-	-	-	-	(188)
18	Total Operating Expense								
19	Before Income Taxes	(2,297)	(85)	(3)	(92)	(289)	-	-	(2,766)
20	State Income Tax	170	6	-	7	21	-	-	204
21	Federal Income Tax	757	28	1	30	94	-	-	910
22	Deferred Taxes and ITCs Ne	-	-	-	-	-	-	-	-
23	Total Operating Expenses	(1,370)	(51)	(2)	(55)	(174)	-	-	(1,652)
24	NET OPERATING INCOME	$ 1,370	$ 51	$ 2	$ 55	$ 174	$ -	$ -	$ 1,652

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ICC Staff Ex. 15.0
Schedule 15.3 N

North Shore Gas Company
Rate Base
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Jurisdictional Rate Base (NS-PGL Ex. JH-2.1N) col. F)	Staff Adjustments (Sch.15.4 N)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Utility Plant	$ 400,247	$ (234)	$ 400,013
2	Accumulated Provision for Depreciation and Amortization	(165,687)	17	(165,670)
3		-	-	-
4	Net Plant	$ 234,560	$ (217)	$ 234,343
5	Additions to Rate Base:			
6	Materials and Supplies	2,414	-	2,414
7	Gas in Storage	6,971	(219)	6,752
8	Budget Plan Balances	834	-	834
9	Cash Working Capital	348	(1,797)	(1,449)
10		-	-	-
11		-	-	-
12	Deductions From Rate Base:			
13	Accumulated Deferred Income Taxes	(48,267)	3	(48,264)
14	Customer Advances for Construction	(511)	-	(511)
15	Customer Deposits	(2,895)	-	(2,895)
16	Retirement Benefits, Net	(13,474)	-	(13,474)
17	Reserve for Injuries and Damages	(1,044)	-	(1,044)
18		-	-	-
19		-	-	-
20		-	-	-
21		-	-	-
22		-	-	-
23	Rate Base	$ 178,936	$ (2,230)	$ 176,706

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ICC Staff Ex. 15.0
Schedule 15.4 N

North Shore Gas Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Incentive Compensation (Sch. 15.7 N)	Non-Union Base Wages (Sch. 15.8 N)	Cash Working Capital (Sch. 17.1 N)	Gas in Storage (Sch. 27.3 N)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Utility Plant	$ (124)	$ (110)	$ -	$ -	$ -	$ -	$ -	$ (234)
2	Accumulated Provision for Depreciation and Amortization	15	2	-	-	-	-	-	17
3		-	-	-	-	-	-	-	-
4	Net Plant	$ (109)	$ (108)	$ -	$ -	$ -	$ -	$ -	$ (217)
5	Additions to Rate Base:								
6	Materials and Supplies	-	-	-	-	-	-	-	-
7	Gas in Storage	-	-	-	(219)	-	-	-	(219)
8	Budget Plan Balances	-	-	-	-	-	-	-	-
9	Cash Working Capital	-	-	(1,797)	-	-	-	-	(1,797)
10		-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-
12	Deductions From Rate Base:	-	-	-	-	-	-	-	-
13	Accumulated Deferred Income Taxes	1	1	-	-	-	-	-	3
14	Customer Advances for Construction	-	-	-	-	-	-	-	-
15	Customer Deposits	-	-	-	-	-	-	-	-
16	Retirement Benefits, Net	-	-	-	-	-	-	-	-
17	Reserve for Injuries and Damages	-	-	-	-	-	-	-	-
18		-	-	-	-	-	-	-	-
19		-	-	-	-	-	-	-	-
20		-	-	-	-	-	-	-	-
21		-	-	-	-	-	-	-	-
22		-	-	-	-	-	-	-	-
23	Rate Base	$ (108)	$ (107)	$ (1,797)	$ (219)	$ -	$ -	$ -	$ (2,230)

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ICC Staff Ex. 15.0
Schedule 15.5 N

North Shore Gas Company
Interest Synchronization Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Rate Base	$ 176,706	(1)
2	Weighted Cost of Debt	2.42%	(2)
3	Synchronized Interest Per Staff (Line 1 x Line 2)	$ 4,276	
4	Company Interest Expense	4,312	(3)
5	Increase (Decrease) in Interest Expense	$ (36)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.300%	$ 3	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 12	

(1) Source: Schedule 15.3, column (d), line 23
(2) Source: ICC Staff Exhibit 22.0, Schedule 22.1
(3) Source: NS-PGL Ex. SM-2.9N

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ICC Staff Ex. 15.0
Schedule 15.6 N

North Shore Gas Company
Gross Revenue Conversion Factor
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	1.000000
2	Uncollectibles	0.7000%	0.007000	
3	State Taxable Income		0.993000	
4	State Income Tax	7.3000%	0.072489	0.073000
5	Federal Taxable Income		0.920511	0.927000
6	Federal Income Tax	35.0000%	0.322179	0.324450
7	Operating Income		0.598332	0.602550
8	Gross Revenue Conversion Factor Per Staff (Line 1 / Line 7)		1.671313	1.659613

North Shore Gas Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Summary		
2	Total Other Production per Staff	$ (28)	Sch. 15.7 N, p. 3 , line 2, cols. (c), (e), (f), & (h)
3	Total Other Production per Company	-	
4	Total Staff Proposed Adjustment to Storage Expense	$ (28)	
5	Total Customer Accounts per Staff	$ (149)	Sch. 15.7 N, p. 3 , line 4, cols. (c), (e), (f), & (h)
6	Total Customer Accounts per Company	-	
7	Total Staff Proposed Adjustment to Customer Accounts Exp.	$ (149)	
8	Total Distribution per Staff	$ (173)	Sch. 15.7 N, p. 3 , line 3, cols. (c), (e), (f), & (h)
9	Total Distribution per Company	-	
10	Total Staff Proposed Adjustment to Distribution Expense	$ (173)	
11	Total Customer Services and Informational Services per Staff	$ (7)	Sch. 15.7 N, p. 3 , line 5, cols. (c), (e), (f), & (h)
12	Total Customer Services and Informational Services per Company	-	
13	Total Staff Proposed Adjustment to Cust./Info. Services Exp.	$ (7)	
14	Total Admin. & General per Staff	$ (1,381)	Sch. 15.7 N, p. 2 , lines 4, 7, 8, and 9 + Sch. 15.7 N, p. 3 , line 6, cols. (c), (e), (f), & (h) + Sch. 15.7 N, p. 4 , lines 4, 7, and 10
15	Total Admin. & General per Company	-	
16	Total Staff Proposed Adjustment to Admin. & General Expense	$ (1,381)	
17	Total Capitalized amount per Staff	$ (124)	Sch. 15.7 N, p. 3 , line 7, cols. (c), (e), (f), & (h) + Sch. 15.7 N, p. 5 , line 4
18	Total Capitalized amount per Company	-	
19	Total Staff Proposed Adjustment to Rate Base	$ (124)	
20	Total Payroll Taxes Per Staff	$ (142)	(Sum of Lines 4, 7, 10, 13, 16 and 19) x 7.65%
21	Total Payroll Taxes Per Company	-	
22	Total Staff Proposed Adjustment to Taxes Other Than Income	$ (142)	
23	Depreciation Expense per Staff	$ (2)	Sch. 15.7 N, p. 3 , line 7, cols. (c), (e), (f) , & (h) x Composite rate of 2.0% per DLH-11.01
24	Depreciation Expense per Company	-	
25	Staff Proposed Adjustment to Depreciation Expense	$ (2)	
26	Accumulated Depreciation per Staff	$ 15	Sch. 15.7 N, p. 1 , line 25 x -1 + Sch. 1.7 N, p. 5 , line 7
27	Accumulated Depreciation per Company	-	
28	Staff Proposed Adjustment to Accumulated Depreciation	$ 15	
29	Accumulated Deferred Income Taxes per Staff	$ 1	Company response to Staff Data Request DLH-23.03
30	Accumulated Deferred Income Taxes per Company	-	
31	Staff Proposed Adjustment to Accum. Def. Income Taxes	$ 1	

North Shore Gas Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Amount	Source
	(a)	(b)	(c)
1	Executive Plan		
2	Administrative and General Total Cost	$ 161	Company Response to DLH-8.02, p. 2
3	Financial Weighting	70%	Company Response to DLH-8.04
4	Executive Plan Financial Goals Cost	$ (113)	Line 2 x line 3 x -1
5	Non-Financial Weighting	30%	Company Response to DLH-8.04
6	Executive Plan Non-Financial Goals Cost	$ 48	Line 5 x line 2
7	Performance Goals Unlikely to be Achieved at 10% of line 6	$ (5)	See Sch. 1.7 N, p, 3, col. (e) x -1
8	Performance Goals Based on Non-PGL Achievements	$ (1)	Lline 7 x line 15
9	Performance Goals Based on IEG Net Income	$ (21)	(Line 6 + line 7 + line 8) x -50%; Company Response to DLH-21.01
10	Allocation for line 8 calculated based upon the percentage of IBS Gas Services and IBS Corp. Services & SSO to total North Shore:		
11	IBS Gas Services	5	Company Response to DLH-13.02
12	IBS Corp. Services & SSO	34	Company Response to DLH-13.03
13	Sub-total	39	
14	Total Exec NS Charges	$ 161	Col. (b) line 2
15	Calculated Allocation percent	24%	Line 14 / line 15

North Shore Gas Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Total Amount	Financial Goals	Subtotal	Performance Goal Unlikely to be Achieved	Performance Goals Based on Non-NS Achievements	Subtotal	Remainder of Perf. Goals Reduced if IEG (parent) Net Income Not Reached
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			(b) x -50%	(b) + (c)	(d) x -10%	(d) x -59%	(d) + (e) + (f)	(g) x -50%
1	Non-Executive Plan							
2	Other Production	$ 30	$ (15)	$ 15	$ (2)	$ (9)	$ 4	$ (2)
3	Distribution	187	(94)	93	(9)	(55)	29	(15)
4	Customer Accounts	161	(81)	80	(8)	(47)	25	(13)
5	Cust. Serv. & Info. Serv.	8	(4)	4	0	(2)	2	(1)
6	Admin. and General	685	(343)	342	(34)	(202)	106	(53)
7	Gross Plant	105	(53)	52	(5)	(31)	16	(8)

Sources by Column:
(b) Company Response to DLH-8.02 pp. 1-2
(c) Weighted at 50% per Response to DLH-8.04
(e) 10% OSHA recordable incidents goal
(f) Allocation calculated based upon the percentage of IBS Gas Services and IBS Corp. Services & SSO to total North Shore:

IBS Gas Services	128	Company Response to DLH-13.02
IBS Corp. Services & SSO	563	Company Response to DLH-13.03
Sub-total	691	
Total Non-Exec NS Charges	$ 1,176	Col. (b) sum of line 2 through 8
Calculated Allocation percent	59%	

(h) Source: Company Response to AG-3.40

North Shore Gas Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description (a)	Amount (b)	Source (c)
1	Stock Plans		
2	Integrys Restricted Stock Unit Award per Staff	$ -	
3	Integrys Restricted Stock Unit Award per Company	251	(1), (2)
4	Staff Proposed Adjustment to Admin. & General Exp.	$ (251)	Line 2 - line 3
5	Integrys Performance Stock Right Agreement per Staff	$ -	
6	Integrys Performance Stock Right Agreement per Company	210	(1), (2)
7	Staff Proposed Adjustment to Admin. & General Exp.	$ (210)	Line 5 - line 6
8	Integrys NonQualified Option Agreement per Staff	$ -	
9	Integrys NonQualified Option Agreement per Company	148	(1)
10	Staff Proposed Adjustment to Admin. & General Exp.	$ (148)	Line 8 - line 9

(1) Source: Company Responses to Staff Data Requests DLH-8.02 and DLH-11.04
(2) $292 from DLH-11.04 Attach. B Revised for Restricted Stock & Performance Stock split 50/50

North Shore Gas Company
Incentive Compensation Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description (a)	Amount (b)	Source (c)
1	Prior Plant Disallowance		
2	Adjustment for Prior Disallowed Plant per Staff	$ (27)	Company Response to DLH-11.01
3	Adjustment for Prior Disallowed Plant per Company	-	Company Response to DLH-11.01
4	Staff Proposed Adjustment to Plant	$ (27)	Line 2 - line 3
5	Adjustment for Accum. Deprec. on Prior Disallowed Plant per Staff	$ 13	Line 10
6	Adjustment for Accum. Deprec. on Prior Disallowed Plant per Company	-	Company Response to DLH-11.01
7	Staff Proposed Adjustment to Accum. Depreciation	$ 13	Line 5 - line 6
8	Accum. Deprec. On Disallowed Plant Balance at 12/31/2009	$ 13	Company Response to DLH-11.01
9	Accum. Deprec. On Disallowed Plant Balance at 12/31/2010	13	Company Response to DLH-11.01
10	Average Balance	$ 13	(Line 8 + Line 9) / 2

North Shore Gas Company
Non-Union Base Wages Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Test Year Amount per Staff	Test Year Amount per Company	Subtotal	Reductions per Company	Staff Proposed Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)
1	Production	$ 154	$ 167	$ (13)		$ (13)
2	Distribution	2,381	2,528	(147)		(147)
3	Customer Accounts	2,797	2,640	157		157
4	Customer Services & Informational Services	380	100	280		280
5	Administrative & General	4,428	4,834	(406)	46	(360)
6	Construction	989	1,099	(110)		(110)
7	Total	$ 11,129	$ 11,368	$ (239)	$ 46	$ (193)
8	Payroll Taxes at line 8 x 7.65%					(15)
9	Depreciation Expense at line 6 x Composite rate of 2% per DLH-20.02					(2)
10	Accumulated Depreciation at line 6 x -1 x Composite rate of 2% per DLH-20.02 x -1					2
11	Company response to Staff Data Request DLH-23.03					1

(b) Source: Sch. 1.8 N, p. 2, col (d)
(c) Source: Company Revised Response to DLH-20.01, Attach 1, col [B]

Total Other Payroll from DLH-20.01 Allocated Based on Test Year Split in DLH-2.02:		
Total Other included in Schedule B-1 per DLH-2.02	$ 1,318	81%
Total Other included in ScheduleC-1, Distribution, per DLH-2.02	319	19%
Total Other Payroll per DLH-2.02	$ 1,637	100%
Test Year Non-Union Base Total Other Payroll of $1,065 Allocated to Constuction at 81%	857	
Test Year Non-Union Base Total Other Payroll of $1,065 Allocated to Distribution at 19%	208	

(d) Source: Col. (b) - Col. (c)
(e) Source: Company Response to DLH-12.07

Company proposed reduction in IBS non-union wage merit increases	$ 46

(f) Source: Col. (d) + Col. (e)

North Shore Gas Company
Non-Union Base Wages Adjustment
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description	Actual 2008 Amount	Calculated 2009 Per Staff	Calculated 2010 Per Staff
	(a)	(b)	(c)	(d)
1	Production	$ 147	$ 150	$ 154
2	Distribution	2,280	2,330	2,381
3	Customer Accounts	2,678	2,737	2,797
4	Customer Services & Informational Services	364	372	380
5	Administrative & General	4,239	4,332	4,428
6	Construction	947	968	989
7	Total	$ 10,655	$ 10,889	$ 11,129

(b) Source: Company Second Revised Response to DLH-20.01, Attach 1, col [D]
Total Other Payroll from DLH-20.01 Allocated Based on Test Year Split in DLH-2.02:
Test Year Non-Union Base Total Other Payroll of $1,129 Allocated to Constuction at 81%
Test Year Non-Union Base Total Other Payroll of $1,129 Allocated to Distribution at 19%

(c) Source: Col. (b) x 1.022
(d) Source: Col. (c) x 1.022

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Schedule 15.9 N

North Shore Gas Company
Adjustment to Invested Capital Taxes
For the Test Year Ending December 31, 2010
(In Thousands)

Line No.	Description (a)	Amount (b)	Source (c)
1	Rate Base	$ 176,706	Staff Ex. 15.0, Schedule 15.1 N, col. i, line 25
2	Rate of Return	7.90%	Staff Ex. 15.0, Schedule 15.1 N, col. i, line 26
3	Operating Income Required	$ 13,952	Line 1 x Line 2
4	Pro forma operating income at present rates adjusted before ICT adjustment	5,916	Staff Ex. 15.0, Schedule 15.1 N, col. d line 24 - Staff Ex. 15.0, Schedule 15.2 N, page 1, col. e line 17
5	Operating Income Additional Allowed	$ 8,036	Line 3 - line 4
6	Invested Capital Tax Rate	0.80%	NS-PGL Ex. SM-2.8N
7	Incremental Invested Capital Tax Impact per Staff	$ 64	Line 5 x line 6
8	Incremental Invested Capital Tax Impact per Company	95	NS-PGL Ex. SM-2.8N
9	Staff Proposed Adjustment	$ (31)	Line 7 - line 8

ICC Docket No. 09-xxxx
The Peoples Gas Light and Coke Company's Response to
Staff Data Requests DLH 1.01-1.10
Dated: March 3, 2009

REQUEST NO. DLH 1.06:

For each Company, provide copies of all incentive compensation expense plans used to develop the test year amounts reported in response to Staff data request DLH-1.04.

RESPONSE:

Please see attached:

Exhibit 1 – Integrys 2008 Executive Incentive Plan
Exhibit 2 – Integrys 2008 Non-Executive Incentive Plan
Exhibit 3 – Integrys 2007 Omnibus Incentive Compensation Plan
Exhibit 4 – Integrys Restricted Stock Unit Award
Exhibit 5 – Integrys Performance Stock Right Agreement
Exhibit 6 – Integrys NonQualified Stock Option Agreement

PERFORMANCE GOALS

Performance goals are approved for both financial and non-financial metrics. The Company believes the goals are highly confidential and will share them only with the Plan participants. These goals will be monitored throughout 2008 and at years end results are presented to the Committee for approval. The specific performance goal targets and weightings for Plan participants will be specified in a supplement to the Plan. Each participant will be provided this information individually on a confidential basis.

PLAN PERFORMANCE MEASURES

The following provides financial and non-financial performance goals for 2008. The Committee has the discretion to adjust the performance measures including results to reflect the effects of extraordinary items, non-recurring items or any other items that the Committee feels should be considered in determining performance results.

Financial Measures

Integrys Energy Group, Inc. Consolidated Net Income

Integrys Energy Group consolidated net income is based off of the "Integrys consolidated income available for common shareholders" as reported in the Company's Form 10-K Annual Report for 2008 and including adjustments approved by the CEO.

MER, MGU, NSG, PGL, UPPCO or WPSC Net Income

Net income is MER, MGU, NSG, PGL, UPPCO or WPSC "allowed utility net income" in the Integrys Energy Group's 2008 budget, as approved by the CEO and the Committee and including adjustments approved by the CEO.

Integrys Combined Regulated Subsidiaries Net Income

The Integrys Combined Regulated Subsidiaries net income target will be the combined total of the MER, MGU, NSG, PGL, UPPCO and WPSC's Integrys incentive plan net income targets.

Integrys Energy Services Net Income

The Integrys Energy Services net income is the 2008 budgeted total net income calculated by replacing after-tax GAAP gross margin with the calculated after-tax Managerial Gross Margin (MGM) on the income statement, as approved by the CEO and the Committee and including adjustments approved by the CEO.

Consolidated Net Income Threshold Requirement

There will be no payouts for financial measure results unless Integrys Energy Group, Inc. Consolidated Net Income threshold outcome level is reached.

Non-Financial Measures

Customer Measure-Billing Quality Index

The Customer Measure for 2008 will be a Billing Quality Index comprised of two measures: Billing Accuracy and Billing Timeliness. Billing Accuracy will measure the percent of monthly bills that are correctly processed. Accurate bills are those that do not need to be cancelled and re-billed or adjusted. Billing Timeliness will measure the percent of bills that are billed on or before the scheduled bill date.

Each of the regulated subsidiaries (MERC, MGU, NSG, PGL, UPPCO and WPSC) will have separate measures of billing accuracy and billing timeliness specific to their own operating unit based on their historical performance. Payouts will increase as the Billing Quality Index increases.

IBS-Corp Services and SSO and IBS-Gas Services will have a combined regulated subsidiary target based on a weighted average of all regulated subsidiaries by number of customers. For 2008, these regulated average percentages will be MER 9.7%, MGU 7.8%, NSG 7.3%, PGL 38.4%, UPPCO 2.4% and WPSC 34.4%. Specific executives will have a combined regulated subsidiary target based on a weighted average of MER 15.3%, MGU 12.3%, NSG 11.6% and PGL 60.8%, or based on UPPCO 6.5% and WPSC 93.5%.

Employee Safety

The recordable incident rate key measure is an injury or illness that is recordable if it meets standard criteria set by Occupational Safety and Health Administration (OSHA) regulations. It indicates the rate at which "recordable incidents" occur in a given year. This rate is then measured against the previous three years' average incident rate. The recordable incident rate will be measured at the following levels:

1. Regulated subsidiaries – measure will rely on the individual metrics of MGU, MER, NSG, PGL, UPPCO and WPSC.
2. IBS Gas Services measure will be dependent upon the combined results of all regulated subsidiaries.
3. IBS Corp Services & SSO measure will be dependent upon the combined results of all regulated subsidiaries and non-regulated subsidiaries. (U.S. locations only)
4. A combined Gas regulated subsidiaries measure applicable only to identified executives will be dependent on the combined results of MGU, MER, NSG and PGL
5. A combined Electric regulated subsidiaries measure applicable only to identified executives will be dependent on the combined results of WPSC and UPPCO only.

Variable Measures – Subsidiary Specific

IBS Corp Services & SSO - Internal Customer Survey

The Internal Customer Survey measurement results will be determined by taking mean scores for each service and comparing them with benchmarking data for other shared services organizations. The target and the outcome satisfaction scores are based on IBS aggregate scores and will be compared to a consolidated shared services benchmark.

MGU, UPPCO, WPSC - System Reliability

The System Reliability measure includes two components, electric system and gas system reliability which measure our ability to deliver quality services to our customers by reducing the frequency and duration of planned and unplanned service interruptions. The electric system component will apply to UPPCO and WPSC. The gas system component will apply to MGU and WPSC. They are defined as follows:

1. The electric system measurement is the 2008 median monthly System Average Interruption Duration Index (SAIDI), without major storms. The monthly SAIDI is the outage minutes, excluding large storms, per customer served. The 2008 incentive target range is determined by the average median SAIDI from 2002 through 2007.
2. The gas system measurement is the 2008 average monthly response time for all customer or public generated odor complaints, excluding all customer delayed response events. Scheduled gas leaks, or those found during normal periodic survey work, are not part of the measure.

PGL - Reduction in System Leaks

The Reduction in Systems Leaks measure is based on the ratio of outside gas leaks cleared as compared to the number of outside gas leaks received.

NSG, PGL - Reduction in 3rd Party Damages

The Reduction in 3rd Party Damages measure is based on the reduction of damages caused by Company crews including those that impact third party facilities as well as company-owned facilities.

MER - Home Services Contracts

The Home Service Contracts measure is based on increasing the number of MER's home services contracts as measured between December 31, 2007 and December 31, 2008.

MER - Lost Time Days

The Lost Time Days measure is based on the total number of days away from work tabulated on the OSHA 300A form section (k) for all MER employees.

MGU - Meter Reading Accuracy

The Meter Reading Accuracy measure is based on percentage of accuracy that meters are read during the prescribed monthly billing window to enable bills to be generated on time using actual meter readings.

IBS Gas Services - First Call Resolution

First Call Resolution is measured by the "Point of Contact Survey" that MER, MGU, NSG and PGL mail to random customers calling each of our call centers. By increasing the percentage of customers whose inquiries are resolved with one contact, Customer Satisfaction will increase and overall Customer Relations operating expenses will be reduced. The measure outcomes are calculated by the number of customers who rate their issue resolved on the first call divided by the total number of customers who respond to this question. All employees within Customer Relations-IBS Gas Group will have a combined subsidiary target based on a weighted average by customer count which will be MER 15.3%, MGU 12.3%, NSG 11.6% and PGL 60.8%.

IBS Gas Services - Day Ahead Forecast Error

The Day Ahead Forecast Error measure calculates the number of occurrences that the volume of natural gas delivered to MGU, NSG, PGL and WPSC is different than the day-ahead forecasted volume by more than a defined tolerance established for this measure. The goal of this measure is to minimize the number of occurrences of significant errors that can create problems and costs.

IBS Gas Services - Meter Repair Costs

The Meter Repair Costs measure is based on measuring the average 2008 in-house cost to test and repair residential class meters for the MER subsidiary as compared to the outside contractor who performed this service for MER in 2006 and 2007. The meter testing, handling and processing costs are added together and divided by the total number of MER meters processed to establish the targets and determine the measure outcome.

WPSC - Market Effectiveness Measure

The WPSC Market Effectiveness measure is specific to WPSC Energy Projects and Energy Supply Operations participants, and selected participants in Energy Supply & Control. It is the energy price weighted availability of all WPSC's generation facilities, the comparison of what WPSC electric generation earns in 2008 versus what it could have earned if all units had been available 100% as needed.

Integrys Energy Services, Inc. - Customer Delight

The Customer Delight measure is defined as "the result of service that surpasses simple satisfaction by surprising the customer through offering products and service at a level either not thought possible or in a form or manner the consumer did not realize they wanted or needed," based on upcoming customer surveys. Incentive targets will be established during the second quarter 2008. Since this measure will not be evaluated on an entire year's experience, the suggested payout target will be determined based on maintaining the baseline score within 10 percent improvement or deterioration in the gap between the baseline and a desired perfection score of 5.0.

Integrys Energy Services, Inc. - Forward Book Value Growth

The Forward Book Value Growth measure is specific to Integrys Energy Services, Inc. and is the change in market value of our portfolio (contractual commitments to customers and associated supply contracts) of retail contracts (natural gas and electricity) and wholesale electric originated customer contracts. This measure will be measured by comparing the total value of the contracts at December 31, 2007 forward with the total value of the contracts measured on December 31, 2008 forward.

ADMINISTRATION

Plan design and administration including payout levels will be approved by the Committee.

Note: Section 162(m) of the Internal Revenue Code limits the tax deduction for compensation paid to the CEO or other Named Executive Officers to $1,000,000 unless certain requirements are met. Those requirements are the Committee consists entirely of outside directors, and

5. Participants receive the payout as current income subject to Federal and State taxes and Social Security withholdings. However, former 401(k) and Deferred Compensation Plans eligible participants may defer a portion of the incentive plan award into the 401(k) and Deferred Compensation Plans with the deferrals subject to the respective plan and tax law limits.

Definition of Pay

Pay for purposes of this Plan is defined as base pay and overtime earnings from the Company for services performed during the payroll year. For purposes of this Plan, the term "Payroll Year" means the period from December 16, 2007 until December 13, 2008.

Incentive Plan Payout

An award is calculated as a percentage of the participant's eligible earnings (as defined under "Definition of Pay") earned over the 26 pay periods represented in the Payroll Year. Awards for performance between threshold and superior may be determined by a non-linear equation.

Plan Performance Goals

Goals, Weightings and Performance Levels

The payout will be based on Company, IBS Corp Support & SSO, IBS Gas Group, NSG, PGL, MER, MGU, UPPCO, and UPPCO's operational and financial performance goals. Each goal is weighted, representing a proportional share of the potential payout. Awards for the performance between threshold and superior may be determined where applicable by a non-linear equation filed in the Compensation department.

Performance goals and weightings for participants at each participating subsidiary are listed as separate addenda to this plan document. The specific subsidiary goals and their targets are listed on Appendix A. The payout weightings for each goal for eligible participant groups are listed on Appendix B.

Consolidated Net Income Threshold Requirement

There will be no payouts for financial measure results unless Integrys Energy Group, Inc. Consolidated Net Income threshold outcome level is reached.

The financial and operational performance measures included in this Plan are as follows:

Financial Measures

<u>Integrys Energy Group Consolidated Net Income</u>

Integrys Energy Group consolidated net income is based off of the "Integrys consolidated income available for common shareholders" as reported in the Company's Form 10-K Annual Report for 2008 and including adjustments approved by the CEO.

MER, MGU, NSG, PGL, UPPCO or WPSC Net Income

Net income is MER, MGU, NSG, PGL, UPPCO or WPSC "allowed utility net income" in the Integrys Energy Group's 2008 budget, as approved by the CEO and the Committee and including adjustments approved by the CEO.

Integrys Combined Regulated Subsidiaries Net Income

The Integrys Combined Regulated Subsidiaries net income target will be the combined total of the MER, MGU, NSG, PGL, UPPCO and WPSC's Integrys incentive plan net income targets.

Non-Financial Measures

Customer Measure-Billing Quality Index

The Customer Measure for 2008 will be a Billing Quality Index comprised of two measures: Billing Accuracy and Billing Timeliness. Billing Accuracy will measure the percent of monthly bills that are correctly processed. Accurate bills are those that do not need to be cancelled and re-billed or adjusted. Billing Timeliness will measure the percent of bills that are billed on or before the scheduled bill date.

Each of the regulated subsidiaries (MERC, MGU, NSG, PGL, UPPCO and WPSC) will have separate measures of billing accuracy and billing timeliness specific to their own operating unit based on their historical performance. Payout levels will increase as the Billing Quality Index increases.

IBS-Corp Services and SSO and IBS-Gas Services will have a combined regulated subsidiary target based on a weighted average of all regulated subsidiaries by number of customers. For 2008, these regulated average percentages will be MER 9.7%, MGU 7.8%, NSG 7.3%, PGL 38.4%, UPPCO 2.4% and WPSC 34.4%. Specific executives will have a combined regulated subsidiary target based on a weighted average of MER 15.3%, MGU 12.3%, NSG 11.6% and PGL 60.8%, or based on UPPCO 6.5% and WPSC 93.5%.

Employee Safety

The recordable incident rate key measure is an injury or illness that is recordable if it meets standard criteria set by Occupational Safety and Health Administration (OSHA) regulations. It indicates the rate at which "recordable incidents" occur in a given year. This rate is then measured against the previous three years' average incident rate. The recordable incident rate will be measured at the following levels:

1. Regulated subsidiaries – measure will rely on the individual metrics of MGU, MER, NSG, PGL, UPPCO and WPSC.
2. IBS Gas Services measure will be dependent upon the combined results of all regulated subsidiaries.
3. IBS Corp Services & SSO measure will be dependent upon the combined results of all regulated subsidiaries and non-regulated subsidiaries. (U.S. locations only)
4. A combined Gas regulated subsidiaries measure applicable only to identified executives will be dependent on the combined results of MGU, MER, NSG and PGL
5. A combined Electric regulated subsidiaries measure applicable only to identified executives will be dependent on the combined results of WPSC and UPPCO only.

Variable Measures – Subsidiary Specific

IBS Corp Services & SSO - Internal Customer Survey

The Internal Customer Survey measurement results will be determined by taking mean scores for each service and comparing them with benchmarking data for other shared services organizations.

MGU, UPPCO, WPSC - System Reliability

The System Reliability measure includes two components, electric system and gas system reliability which measures our ability to deliver quality services to our customers by reducing the frequency and duration of planned and unplanned service interruptions. The electric system component will apply to UPPCO and WPSC. The gas system component will apply to MGU and WPSC. They are defined as follows:

1. The electric system measurement is the 2008 median monthly System Average Interruption Duration Index (SAIDI), without major storms. The monthly SAIDI is the outage minutes, excluding large storms, per customer served. The 2008 incentive target range is determined by the average median SAIDI from 2002 through 2007.
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PGL - Reduction in System Leaks

The Reduction in Systems Leaks measure is based on the ratio of outside gas leaks cleared as compared to the number of outside gas leaks received.

NSG, PGL - Reduction in 3rd Party Damages

The Reduction in 3rd Party Damages measure is based on the reduction of damages caused by Company crews including those that impact third party facilities as well as company-owned facilities.

MER - Home Services Contracts

The Home Service Contracts measure is based on increasing MER's home services contracts as measured between December 31, 2007 and December 31, 2008.

MER - Lost Time Days

The Lost Time Days measure is based on the total number of days away from work tabulated on the OSHA 300A form section (k) for all MER employees.

MGU - Meter Reading Accuracy

The Meter Reading Accuracy measure is based on percentage of accuracy that meters are read during the prescribed monthly billing window to enable bills to be generated on time using actual meter readings.

IBS Gas Services - First Call Resolution

First Call Resolution is measured by the "Point of Contact Survey" that MER, MGU, NSG and PGL mail to random customers calling each of our call centers. By increasing the percentage of customers whose inquiries are resolved with one contact, Customer Satisfaction will increase and overall Customer Relations operating expenses will be reduced. The measure outcomes are calculated by the number of customers who rate their issue resolved on the first call divided by the total number of customers who respond to this question. All employees within Customer Relations-IBS Gas Group will have a combined subsidiary target based on a weighted average by customer count which will be MER 15.3%, MGU 12.3%, NSG 11.6% and PGL 60.8%.

IBS Gas Services - Day Ahead Forecast Error

The Day Ahead Forecast Error measure calculates the number of occurrences that the volume of natural gas delivered to MGU, NSG, PGL and WPSC is different than the day-ahead forecasted volume by more than a tolerance established for this measure. The goal of this measure is to minimize the number of occurrences of significant errors that can create problems and costs.

IBS Gas Services - Meter Repair Costs

The Meter Repair Costs measure is based on measuring the average 2008 in-house cost to test and repair residential class meters for the MER subsidiary as compared to the outside contractor who performed this service for MER in 2006 and 2007. The meter testing, handling and processing costs are added together and divided by the total number of MER meters processed to establish the targets and determine the measure outcome.

WPSC - Market Effectiveness Measure

The WPSC Market Effectiveness measure is specific to WPSC Energy Projects and Energy Supply Operations participants, and selected participants in Energy Supply & Control. It is the energy price weighted availability of all WPSC's generation facilities, the comparison of what WPSC electric generation earns in 2008 versus what it could have earned if all units had been available 100% as needed.

Rights of Participants & Forfeiture

Nothing in this Plan shall:

1. Confer upon any employee any right with respect to continuation of employment with the Company;
2. Interfere in any way with the right of the Company to terminate his/her employment at any time; or
3. Confer upon any employee or any other person any claim or right to any distribution under the Plan except in accordance with its terms.

No right or interest of any employee in the Plan shall, prior to actual payment or distribution to the employee, be assignable or transferable in whole or in part, either voluntarily or by operation of law or otherwise, or be subject to payment of debts of any employee by execution, levy, garnishment, attachment, pledge, bankruptcy, or in any other manner.

2008 Integrys Non-Executive Incentive Plan Measures Weightings

No Financial Measures Payouts for any Participants unless Integrys Energy Group, Inc. Net Income Threshold Outcome is Reached

	IBS Corp/SSO	IBS Gas Svcs	NSG	PGL
PERFORMANCE GOAL	**Weighting**	**Target**	**Weighting**	**Target**
Financial-Net Income (millions)				
Integrys Energy Group, Inc.	50%		25%	25%
Subsidiary-Specific			25%	25%
Combined Regulated Subsidiaries*		50%		
Employee Safety				
OSHA-Recordable Incident Rates**	10%	10%	10%	10%
Customer Measure-Billing Quality Index				
Subsidiary-Specific by Range			20%	20%
Combined Reg Subs by Range***	20%	20%		
Subsidiary Variable				
Internal Customer Survey	20%			
Electric Reliability				
Gas Reliability				
Reduction in System Leaks				10%
Reduction-3rd Party Damages			20%	10%
Home Services Contracts				
Lost Time Days				
Meter Reading Accuracy				
First Call Resolution****		20%		
Day Ahead Forecast Error (days)*****		20%		
Meter Repair Costs (per meter)******		20%		
Market Effectiveness				

Notes:

* Includes MER, MGU, NSG, PGL, UPPCO and WPSC net income targets

** Safety measure for IBS Corp & SSO based on TEG U.S. consolidated results; for IBS Gas Services based on all regulated utilities

*** IBS Corp & SSO, and IBS Gas Services have a combined regulated subsidiary target based on a weighted average

**** Applies only to IBS Gas Services-Customer Value Organization

***** Applies only to IBS Gas Services-Gas Supply Organization

****** Applies only to IBS Gas Services-Gas Engineering Organization

WPSC Electric & Gas reliability variable measures apply to all WPSC participants except Energy Supply Operations, Energy Projects and ES & C

WPSC Market Effectiveness variable measure applies only to Energy Supply Operations, Energy Projects and ES & C

ICC Docket No. 09-xxxx
The Peoples Gas Light and Coke Company's Response to
Staff Data Requests DLH 1.01-1.10
Dated: March 3, 2009

REQUEST NO. DLH 1.08a:

For each Company, for each incentive compensation expense plan provided in response to Staff data request DLH-1.07, provide the actual 2007 and 2008 (most recent period available) results, financial or otherwise.

RESPONSE:

Please refer to the attached for the PGL/NSG annual incentive plan results for 2007 and 2008.

The plan ending in February 2007 with the formation of Integrys was paid at target.

In addition, below is information on equity grants provided to employees in 2007 and 2008 for your reference.

2007 – 240,130 Stock Options
40,590 Performance Shares
30,006 Restricted Stock Units

2008 - 684,404 Stock Options
125,600 Performance Shares
86,165 Restricted Stock Units

PGL 2007 Non-Executive Results

Measures	Results
Net Income	
• Subsidiary-specific	Below Target
• Integrys Energy Group	At Target
System Reliability	
• Gas Response Time	At Target
Employee Safety	
• Incident Rate	Below Target
Customer Value	
• Residential	Above Target
Rates	
• Avg. Gas Dist. Cost	Above Target
Diversity	
• External new hires (Minority & Female)	Above Target
• Hires & Promotions (Mgr. & Above)	At Target

PGL 2008 Non-Executive Results

Measures	Results
Net Income	
• Subsidiary-specific	Below Target
• Integrys Energy Group	Below Target
Employee Safety	
• Incident Rate	Below Target
Customer Value	
• Billing Quality Index	Above Target
Subsidiary Specific	
• Reduction in System Leaks	Below Target
• Reduction in 3rd Party Damages	Above Target

NSG 2007 Non-Executive Results

Measures	Results
Net Income	
• Subsidiary-specific	Below Target
• Integrys Energy Group	At Target
System Reliability	
• Gas Response Time	At Target
Employee Safety	
• Incident Rate	Below Target
Customer Value	
• Residential	Above Target
Rates	
• Avg. Gas Dist. Cost	Above Target
Diversity	
• External new hires (Minority & Female)	Above Target
• Hires & Promotions (Mgr. & Above)	At Target

NSG 2008 Non-Executive Results

Measures	Results
Net Income	
• Subsidiary-specific	Above Target
• Integrys Energy Group	Below Target
Employee Safety	
• Incident Rate	Below Target
Customer Value	
• Billing Quality Index	Above Target
Subsidiary Specific	
• Reduction in 3rd Party Damages	Above Target

ICC Docket No. 09-0166/0167
The Peoples Gas Light and Coke Company's Response to
Staff Data Requests DLH 21-01-21.02
Dated: May 15, 2009

REQUEST NO. DLH 21.01:

According to Peoples Gas' response to The People of the State of Illinois ("AG") Data Request AG-3.40 and North Shore's response to AG-3.82, the Integrys 2009 Non-Executive Incentive Plan includes a condition that if the consolidated net income threshold performance level is not reached, any earned non-financial measure payout will be reduced by 50%. Does the Integrys 2009 Executive Incentive Plan also include such a provision? If no, explain the Company's rationale for the difference in the two plans.

RESPONSE:

The Integrys 2009 Executive Incentive Plan (applies to NS and PGL) includes the requirement regarding Consolidated Net Income – if the Consolidated Net Income threshold is not reached, any earned non-financial measures payouts will be reduced by fifty (50) percent.

ICC Docket No. 09-xxxx
The Peoples Gas Light and Coke Company's Response to
Staff Data Requests DLH 8.01-8.06
Dated: March 19, 2009

REQUEST NO. DLH 8.06:

Referring to the Company's response to Staff data request DLH-1.04, amounts reported in the "Stock options, etc" tab, please explain how changes in the price of Integrys Energy Group, Inc. stock are expected to change the Company's forecast of test year incentive compensation expenses provided in this tab. If the price changes are not expected to make a difference in the forecast amount, explain why or how that is possible. Provide all supporting workpapers, calculations, and allocations of the amounts in this response. If applicable, provide workpapers and supporting documents in Excel format with working formulas.

RESPONSE:

Amounts reported in the "Stock options, etc" tab in response to Staff data request DLH-1.04 include costs related to both past grants as well as estimates for future grants. For actual grants (performance shares, stock options, restricted stock), the Company is required to record cost for these types of compensation using the accounting prescribed in Statement of Financial Accounting Standard No. 123R (SFAS 123R). SFAS 123R sets the framework for how to calculate the cost of the grant as well as the period of time over which the cost should be recorded.

The costs included in the 2010 test year related to past grants were determined at the time of those past grants. Once the cost of the grant has been calculated, changes in the Integrys stock price have no impact on the cost that must be recognized. The following details how changes to the Integrys stock price impacts incentive compensation expense to be recorded when an actual grant is made:

Long Term Variable Pay Plan - Integrys Energy Group, Inc. hires an external party to value its long term variable pay plan (performance share) grants using a Monte Carlo model. This model incorporates factors associated with the performance of Integrys' stock price and shareholder returns over the term of the grants, including total stock return volatility and dividend yield. The model also takes into consideration the relative performance of Integrys' stock price and shareholder returns relative to its peer group. As these stock price inputs change so does the fair value of the grant and correspondingly the amount of expense to be recorded on PGL's books.

Stock Options - Integrys Energy Group, Inc. hires an external party to value its stock option grants using a lattice valuation model. One of the inputs to this model is the historical stock return volatility which is based on the weekly closing price of Integrys' stock. As the volatility percentage increases, the value of the stock options increases. Another input is the dividend yield which incorporates both the quarterly dividend amounts and the closing stock price for each dividend date. As the dividend yield increases, the value of the stock options decreases. The calculated fair value is used as the basis for recording expense on PGL's books.

ICC Docket No. 07-xxxx
The Peoples Gas Light and Coke Company's Response to
Staff Data Requests DLH 8.01-8.06
Dated: March 19, 2009

Restricted Stock - The restricted stock granted is valued using the stock price on the grant date so as the stock price increases the expense recorded on PGL's books increases. Likewise, a decrease in the stock price reduces the amount of expense to be recorded.

Costs in the 2010 test year also include estimated future grants, the accounting for which was also in accordance with SFAS 123R. This is important because of the period of time over which the expense needs to be recognized. While changes in the stock price will ultimately have an impact on the value of a grant, for budget purposes, we assumed that any changes in stock price (up or down) would be reflected in the number of shares granted and, therefore, would not have an impact on projected future costs. For example, if the stock price decreased, more shares would be awarded to keep the value of the equity grant the same. Likewise, if the stock price increased, fewer shares would be awarded to keep the value of the equity grants the same. To project the cost of the 2009 grants, we used the actual February 2008 grant costs for each of these plans and increased them by 5%. We then increased the projected 2009 expense amounts by 5% to arrive at the budgeted 2010 costs.

ICC Docket No. 09-0166/0167
The Peoples Gas Light and Coke Company's Response to
Staff Data Requests DLH 23.01-23.04
Dated: July 24, 2009

REQUEST NO. DLH 23.04:

For Peoples Gas, provide in Word format in legislative style compared to its direct proposal the revised version of Rider ICR that the Company recommends be adopted by the Commission.

RESPONSE:

PGL DLH 23.04 Attach 01, in legislative style, is a revised version of Rider ICR that Peoples Gas recommends be adopted by the Commission.

RIDER TO SCHEDULE OF RATES FOR GAS SERVICE

Rider ICR

Infrastructure Cost Recovery

Applicable to Service Classification Nos. 1, 2, 4 and 8

The Infrastructure Cost Recovery Charge shall be determined in accordance with the provisions of this rider. The Infrastructure Cost Recovery Charge shall be applied to bills of customers.

Section A – Applicability

The purpose of the ICR Charge is to recover a return on, and depreciation expense related to, the Company's investment in QIP net of related savings as described in Section D of this rider.

On or before March 20 of each year, the Company shall file with the Commission an information sheet specifying the ICR Charge Percentage to be effective for service rendered during the period of April 1 through December 31 of such year. Such filing shall include a statement showing the determination of such Percentage under Sections F and G and supporting data. The initial charge to be determined under this rider shall be effective April 1, 2011.

Section B – Definitions

As used in this rider, the terms below are defined as follows:

"Act" means the Public Utilities Act [220 ILCS 5/1-101 et seq.].

“Annual ICR Base Rate Revenues” mean ICR Base Rate Revenues for the calendar year period beginning January 1 and ending December 31 of the Effective Period.

“Effective Period” means a period commencing April 1 and ending the following December 31.

“Excluded Credits” mean credits resulting from Riders 2, EEP, and SBO.

“Excluded Revenues” means revenues arising from Service Classification Nos. 5 and 7 and Riders 1, 2, 9,11, EEP, FST, SST, P, CFY, AGG, SBO, UEA, and IT and revenues arising from ICR Charges.

"ICR Base Rate Revenues" mean revenues recorded in Accounts 480, 481, 482 and 489. ICR Base Rate Revenues, however, shall not include any Excluded Revenues and shall not be reduced by any Excluded Credits.

"ICR Charge Percentage" is the percentage determined in accordance with Section F of this rider.

"Infrastructure Cost Recovery Charge" or "ICR Charge" means the amount added to a customer bill when the ICR Charge Percentage is applied in accordance with Section F (a) of this rider.

"Operation Year" means any calendar year after the Test Year.

"Qualifying Infrastructure Plant" or “QIP” means certain plant that is not reflected in the rate base used to establish the Company's base rates and is consistent with the terms of Section D of this rider.

Asterisks not needed replacing this sheet in its entirety.

Issued by James F. Schott, Vice President
130 East Randolph Drive, Chicago, Illinois 60601

RIDER TO SCHEDULE OF RATES FOR GAS SERVICE

Rider ICR

Infrastructure Cost Recovery

Applicable to Service Classification Nos. 1, 2, 4 and 8

Section B – Definitions, continued

"QIP Costs" mean Qualifying Infrastructure Plant costs that are recoverable through the ICR Charge as determined in accordance with Section F of this rider.

"QIP Percent" means the percentage for each applicable category of QIP that is to be applied to QIP Costs as set forth in Sections F and H of this rider. The initial QIP Percent for Accounts 381 and 383, as set forth in Section D of this rider, shall be 10% and 90~~4~~%, respectively. The QIP Percent shall be re-determined each reconciliation year as described in Section H(c) of this rider and shall be applicable for the Effective Period immediately following the reconciliation year.

"Test Year" means the test year period used by the Company in its last rate case as defined in 83 Ill. Adm. Code Sec. 287.20.

Section C - Terms and Conditions

(a) The annual amount to be billed under Rider ICR shall not exceed the product of Annual ICR Base Rate Revenues multiplied by 5%~~The ICR Charge shall not exceed 5% of Annual ICR Base Rate Revenues~~. The ICR Charge Percentage shall only be applied to charges which derive ICR Base Rate Revenues.

(b) On the effective date of new base rates that provide for the recovery of the costs that had previously been recovered under this rider, the ICR Charge Percentage shall be reset to zero.

(c) The ICR Charge, which shall be the product of the ICR Charge Percentage times applicable base rate charges for the Effective Period, shall be presented as a separate line item on customer bills.

(d) The revenues resulting from this rider shall be recorded in a separate revenue sub-account.

Section D – Qualifying Infrastructure Plant

(a) To be classified as QIP, the plant additions must meet the following criteria:

(1) Plant additions must be replacements of existing plant items from the accounts listed in subsection (b) or additions required to support replacement of existing plant items from the accounts listed in subsection(b) or additions required to be installed as part of the Company's main replacement program;

(2) Such replacements are installed to replace cast iron and ductile iron main and ancillary infrastructure; and

(3) Such replacements were not included in the calculation of the rate base in the Company's last rate case.

Issued by James F. Schott, Vice President
130 East Randolph Drive, Chicago, Illinois 60601

PGL 00131142

RIDER TO SCHEDULE OF RATES FOR GAS SERVICE

Rider ICR

Infrastructure Cost Recovery

Applicable to Service Classification Nos. 1, 2, 4 and 8

Section D – Qualifying Infrastructure Plant, continued

(b) The plant additions shall include items from the following accounts, pursuant to 83 Ill. Adm. Code Part 505:

(1) Account 376, Distribution Mains;
(2) Account 378, Measuring and Regulating Station Equipment, General;
(3) Account 379, Measuring and Regulating Station Equipment, City Gate Check Stations;
(4) Account 380, Services;
(5) Account 381, Meters including Meter Installations; and
(6) Account 383, House Regulators

(c) QIP shall include only plant additions installed or estimated to be installed on or after January 1 of the year in which the Company files its initial ICR Charge Percentage and shall exclude incentive compensation expenses. For Accounts 381 and 383, QIP shall include all Company additions installed or estimated to be installed and adjusted by the applicable QIP Percent as defined in Section B of this rider.

Section E - Recoverable Qualifying Infrastructure Plant Costs

QIP costs shall include the pre-tax return on QIP and the depreciation expense applicable to QIP.

(1) PTR means pre-tax return and is calculated using the weighted cost of debt and weighted cost of equity determined in the Company's last rate case. The weighted cost of equity is multiplied by the gross revenue conversion factor. The product is then added to the weighted cost of debt to obtain the pre-tax return. The pre-tax return is calculated using the following formulas:

$$GRCF = \frac{1}{(1-UE)\,(1 - SIT)\,(1 - FIT)}$$

$$PTR = (WCCE \times GRCF) + WCD$$

Where:

GRCF = Gross Revenue Conversion Factor.

UE = The uncollectible expense percentage from the Company's last rate case.

SIT = Effective Illinois State income tax rate.

FIT = Effective Federal income tax rate.

PTR = Pre-tax return.

WCCE = Weighted cost of common equity from the Company's last rate case.

WCD = Weighted cost of debt from the Company's last rate case.

(2) Depreciation expense shall be calculated monthly by applying the Company's approved depreciation rates, including removal and salvage, to the beginning and ending month average QIP balance for each category of QIP as described in Section D of this rider.

PGL 0013143

Asterisks not needed replacing this sheet in its entirety.

Issued by James F. Schott, Vice President
130 East Randolph Drive, Chicago, Illinois 60601

PGL 0013144

RIDER TO SCHEDULE OF RATES FOR GAS SERVICE

Rider ICR

Infrastructure Cost Recovery

Applicable to Service Classification Nos. 1, 2, 4 and 8

Section F - Determination of the Infrastructure Cost Recovery Charge Percentage

(a) The ICR Charge Percentage shall be expressed as a percentage carried to two decimal places. The ICR Charge Percentage shall be applied to the total amount billed to each customer based on the Company's applicable charges that would derive ICR Base Rate Revenues for the Effective Period.

(b) The ICR Charge Percentage for an Effective Period shall be determined by using the following formula:.

$$ICR\% = \frac{(OQIP \times PTR) + NetDep \cancel{+ IOM} - SV + RA +- O + INT}{BRR} \times 100$$

Where:

ICR% = ICR Charge Percentage.

OQIP =

(i) For Accounts 376, 378, 379 and 380, the average forecasted cost of the investment in QIP, less forecasted retirements, less forecasted accumulated depreciation. The average forecasted cost of QIP, net of retirements and accumulated depreciation, shall be computed by using an average of the balances of QIP, retirements and accumulated depreciation for December 31 of the year preceding the Operation Year and December 31 of the Operation Year.

(ii) For Accounts 381 and 383, the average forecasted cost of the investment in QIP less retirements, less forecasted accumulated depreciation, all multiplied times the applicable QIP Percent. The average forecasted cost of QIP, net of retirements and accumulated depreciation, shall be computed by using an average of the balances of QIP, retirements and accumulated depreciation for December 31 of the year preceding the Operation Year and December 31 of the Operation Year.

(iii) OQIP shall be the sum of the amounts in (i) and (ii).

PTR = Pre-tax return as described in Section E (1) of this rider.

NetDep = Depreciation expense as described in Section E(2). For Accounts 381 and 383, Deprecation Expense shall be applied to the QIP adjusted for its respective QIP Percent. NetDep shall be the sum of NetDep calculated for each QIP Account.

~~IOM = Incremental operation and maintenance expenses arising from the cost of program management and additional labor. IOM shall not include any costs recovered in base rates in the Company's most recent rate case.~~

130 East Randolph Drive, Chicago, Illinois 60601

PGL 0013146

RIDER TO SCHEDULE OF RATES FOR GAS SERVICE

Rider ICR

Infrastructure Cost Recovery

Applicable to Service Classification Nos. 1, 2, 4 and 8

Section F - Determination of the Infrastructure Cost Recovery Charge Percentage, continued

SV = Savings, which is determined as $6,000.00 times the number of miles of cast iron and ductile iron that is abandoned or estimated to be abandoned under the Company's main replacement program in the Operation Year.

RA = Company-determined reconciliation component calculated for the reconciliation year under the reconciliation feature as described in Section H (c) of this rider. The reconciliation component shall be collected over nine months from April through December. The reconciliation year shall be the Operation Year of the preceding Effective Period.

BRR = The Company's forecasted ICR Base Rate Revenues for the Effective Period.

O = An amount ordered by the Commission as described in Section H(a) of this rider.

INT = The calculated interest attributable to the O component. This interest shall be calculated as described in Section H(a) of this rider.

Section G - Information Sheet Filings

The ICR Charge Percentage shall be filed on an information sheet with supporting data no later than March 20. An information sheet with supporting data filed after that date, but prior to the effective date, shall be accepted only if it corrects an error or errors from a timely filed information sheet for the same effective date. Any other information sheet with supporting data shall be accepted only if submitted as a special permission request to become effective on less than 45 days notice under the provisions of Section 9-201(a) of the Act.

Section H - Annual Reconciliation

(a) No later than March 31 of e~~E~~ach year following the first Effective Period, the Company shall file a petition, testimony and reconciliation statement seeking initiation of an annual reconciliation hearing. Upon review of the Company's filing, the Commission may require a hearing to receive from the Company such evidence as the Commission requires regarding any aspect of determining the charges under this rider, including a determination of whether all costs recovered under this rider were prudently incurred, just and reasonable. If the Commission finds, after hearing, that any amounts were incorrectly debited or credited to the rider during the applicable Effective Period, the Commission may by order require that the rider be adjusted by appropriate credits or debits thereto. Any adjustments so ordered shall be reflected as Factor O in the ICR Charge Percentage formula in Section F over a succeeding Effective Period. Amounts either collected or refunded through the O component shall accrue interest at the rate established by the Commission under 83 Ill. Adm. Code Sec. 280.70(e)(1). Interest on the O component shall be applied from the end of the reconciliation year until the O component is refunded or charged to ratepayers through the ICR Charge.

RIDER TO SCHEDULE OF RATES FOR GAS SERVICE

Rider ICR

Infrastructure Cost Recovery

Applicable to Service Classification Nos. 1, 2, 4 and 8

Section H - Annual Reconciliation, continued

(b) Any adjustment made through the RA component shall be in effect for nine months commencing on the April 1 immediately following submittal of the annual reconciliation.

(c) The Company shall calculate the RA component using the following formula:

RA = (ActNetQIP x PTR) + ActNetDep – ActSav ~~+ ActIOM~~ - ICRRev + RApy + Opy

Where:

RA = Company-determined reconciliation component.

ActNetQIP = The average actual cost of the investment in QIP for the reconciliation year less actual retirements, less actual accumulated depreciation of QIP for the reconciliation year. The average actual cost of QIP, net of retirements and depreciation, shall be computed by using an average of year end balances of QIP and accumulated depreciation for December 31 of the year preceding the reconciliation year and December 31 of the reconciliation year. For the purposes of this rider, the actual cost of the investment in QIP for Accounts 381 and 383 in any reconciliation year shall equal the average actual cost of the total investment for each Account for the reconciliation year less actual retirements, less actual accumulated deprecation, all multiplied times the actual QIP Percent. The actual QIP Percent will be determined separately for Accounts 381and 383 by dividing the actual number of units installed during the reconciliation year under the Company's main replacement program by the total number of units purchased during the reconciliation year. The Company will submit data to the Commission with its filing which supports the determination of the actual QIP Percent.

PTR = Pre-tax return as described in Section E (1) of this rider.

ActNetDep = Actual depreciation expense related to the average investment in each category of QIP for the reconciliation year. Depreciation expense shall be calculated monthly by multiplying the actual investment in QIP by plant account, net of retirements, by the approved depreciation rates, including removal and salvage, to the beginning and ending month average QIP for the respective accounts as described in Section D of this rider. For Accounts 381 and 383, Deprecation Expense shall be applied to the QIP adjusted for its respective QIP Percent.

ActSav = Actual savings, which is determined as $6,000.00 times the actual number of miles of cast iron and ductile iron main abandoned in the reconciliation year. The Company shall update ActSav no less than every three years. The first such update shall be required in the Company's third annual reconciliation proceeding, but may be updated sooner if demonstrated to be necessary by the Company or the Commission.

~~ActIOM = Actual incremental operation and maintenance costs for the reconciliation year.~~

ICRRev = Actual ICR revenues collected during the reconciliation year through the ICR Charge.

Date Issued: FEBRUARY 25, 2009 **Date Effective:** APRIL 11, 2009
Asterisks not needed replacing this sheet in its entirety.

Issued by James F. Schott, Vice President
130 East Randolph Drive, Chicago, Illinois 60601

Rider ICR

Infrastructure Cost Recovery

Applicable to Service Classification Nos. 1, 2, 4 and 8

Section H - Annual Reconciliation, continued
RApy = The RA component from the previous reconciliation year.

Opy = The sum of the O component and the calculated interest attributable to the O component included in the calculation of the ICR Charge Percentage during the previous reconciliation year.

Section I – Annual Internal Audit

The Company shall submit annually to the Manager of the Accounting Department of the Commission's Financial Analysis Division, no later than September 1, an internal audit report that determines whether the ICR Charge and information provided in Section H have been calculated in accordance with this rider. The initial internal audit under this rider shall be submitted no later than September 1, 2012. All internal audits conducted under this rider shall include at least the following tests:

(1) A test that costs recovered through Rider ICR are not recovered through other approved tariffs;
(2) At test of customer bills to confirm that all Rider ICR Adjustments are being properly billed to customers in the correct time periods;
(3) A test that Rider ICR revenues are properly stated; and
(4) A test that actual costs are being identified and recorded properly to be reflected in the calculation of the ICR Charge Percentage and the annual reconciliation completed under this rider.

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Date Issued: FEBRUARY 25, 2009 **Date Effective:** APRIL 11, 2009
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Issued by James F. Schott, Vice President
130 East Randolph Drive, Chicago, Illinois 60601

ICC Docket No. 09-0166/0167
The Peoples Gas Light and Coke Company's Response to
Staff Data Requests DLH 23.01-23.04
Dated: July 24, 2009

REQUEST NO. DLH 23.01:

Provide an update in Excel format to the Companies' responses to Staff data request DLH-3.10 based upon the Companies' rebuttal revenue requirements.

RESPONSE:

PGL DLH 23.01 Attach 01 is an Excel file of the proposed Rider VBA rate case margins, customers and margin per customer by rate class based on the Company's rebuttal revenue requirements in this case.

REVISED RESPONSE:

PGL DLH 23.01 REV Attach 01 is a revised Excel file of the proposed Rider VBA rate case margins, customers and margin per customer by rate class based on the Company's rebuttal revenue requirements in this case. The SC No. 2 distribution charge rates have been revised to correct a minor formulaic error.

The Peoples Gas Light and Coke Company
Docket No. 09-0167
Attachment to Staff Data Request DLH-23.01

Proposed Rider VBA Rate Case Margin per customer - 2010 - REBUTTAL Rates - Revisec

Description	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 May	2010 Jun	2010 Jul	2010 Aug	2010 Sep	2010 Oct	2010 Nov	2010 Dec	Annual	Total
SC No. 1														
Rate Case Customers (RCC)	763,497	763,751	808,683	778,390	806,492	732,964	757,630	774,857	726,833	788,209	760,753	778,931	770,083	9,240,990
Distribution therms														
Block 1	32,548,828	32,393,394	33,251,648	29,564,903	20,759,101	14,664,149	13,951,849	13,496,526	17,715,050	24,560,491	28,843,055	32,743,692	294,492,686	
Block 2	97,494,668	80,868,553	64,395,092	29,671,138	6,899,475	847,712	635,869	447,369	2,129,712	13,359,450	47,300,807	84,111,339	428,161,184	
Total	130,043,496	113,261,947	97,646,740	59,236,041	27,658,576	15,511,861	14,587,718	13,943,895	19,844,762	37,919,941	76,143,862	116,855,031	722,653,870	
Distribution rate block 1	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896		
Distribution rate block 2	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665		
Distribution Revenue / Rate Case Margin														
Distribution Rev Block 1	$ 12,009,215.58	$ 11,951,866.65	$ 12,268,528.05	$ 10,908,266.61	$ 7,659,277.90	$ 5,410,484.42	$ 5,147,674.21	$ 4,979,678.23	$ 6,536,144.85	$ 9,061,838.76	$ 10,641,933.57	$ 12,081,112.60	$ 108,656,021.43	
Distribution Rev Block 2	$ 13,322,646.38	$ 11,050,687.77	$ 8,799,589.32	$ 4,054,561.01	$ 942,813.26	$ 115,839.84	$ 86,891.50	$ 61,132.97	$ 291,025.14	$ 1,825,568.84	$ 6,463,655.28	$ 11,493,814.47	$ 58,508,225.78	
Total Distribution Revenue (RCM)	$ 25,331,861.96	$ 23,002,554.42	$ 21,068,117.37	$ 14,962,827.62	$ 8,602,091.16	$ 5,526,324.26	$ 5,234,565.71	$ 5,040,811.20	$ 6,827,169.99	$ 10,887,407.60	$ 17,105,588.85	$ 23,574,927.07	$ 167,164,247.21	
Rate Case Margin per customer	$ 33.18	$ 30.12	$ 26.05	$ 19.22	$ 10.67	$ 7.54	$ 6.91	$ 6.51	$ 9.39	$ 13.81	$ 22.49	$ 30.27	$ 217.07	
SC No. 2														
Rate Case Customers (RCC)	83,364	83,250	87,291	84,295	86,779	80,626	84,245	84,919	79,503	85,090	81,940	84,548	83,821	1,005,850
Distribution therms														
Block 1	7,508,557	7,459,029	7,477,112	6,429,816	4,486,081	3,603,894	3,452,565	3,563,585	4,038,650	5,183,174	6,185,537	7,415,271	66,803,271	
Block 2	74,805,704	66,024,740	57,609,952	37,723,581	17,198,839	9,943,272	10,286,583	10,541,636	14,563,723	25,022,373	48,201,666	67,224,856	439,146,925	
Block 3	37,884,868	27,653,325	23,399,636	14,507,808	6,766,219	3,276,727	3,345,271	2,254,437	4,241,030	7,724,968	19,834,507	33,681,520	184,570,316	
Total	120,199,129	101,137,094	88,486,700	58,661,205	28,451,139	16,823,893	17,084,419	16,359,658	22,843,403	37,930,515	74,221,710	108,321,647	690,520,512	
Distribution rate block 1	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638		
Distribution rate block 2	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376		
Distribution rate block 3	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596		
Distribution Revenue / Rate Case Margin														
Block 1	$ 2,525,728.40	$ 2,509,068.18	$ 2,515,150.93	$ 2,162,861.51	$ 1,509,027.93	$ 1,212,277.86	$ 1,161,373.81	$ 1,198,718.72	$ 1,358,521.09	$ 1,743,516.07	$ 2,080,690.94	$ 2,494,348.86	$ 22,471,284.30	
Block 2	$ 10,754,068.01	$ 9,491,716.62	$ 8,282,006.70	$ 5,423,142.00	$ 2,472,505.09	$ 1,429,444.78	$ 1,478,799.17	$ 1,515,465.59	$ 2,093,680.82	$ 3,597,216.34	$ 6,929,471.50	$ 9,664,245.30	$ 63,131,761.92	
Block 3	$ 4,393,129.29	$ 3,206,679.57	$ 2,713,421.79	$ 1,682,325.42	$ 784,610.76	$ 379,969.26	$ 387,917.63	$ 261,424.51	$ 491,789.84	$ 895,787.29	$ 2,300,009.43	$ 3,905,709.06	$ 21,402,773.85	
Total Distribution Revenue (RCM)	$ 17,672,925.70	$ 15,207,464.37	$ 13,510,579.42	$ 9,268,328.93	$ 4,766,143.78	$ 3,021,691.90	$ 3,028,090.61	$ 2,975,608.82	$ 3,943,991.75	$ 6,236,519.70	$ 11,310,171.87	$ 16,064,303.22	$ 107,005,820.07	
Rate Case Margin per customer	$ 212.00	$ 182.67	$ 154.78	$ 109.95	$ 54.92	$ 37.48	$ 35.94	$ 35.04	$ 49.61	$ 73.29	$ 138.03	$ 190.00	$ 1,276.60	

ICC Docket No. 09-0166/0167
North Shore Gas Company's Response to
Staff Data Requests DLH 23.01-23.04
Dated: July 24, 2009

REQUEST NO. DLH 23.01:

Provide an update in Excel format to the Companies' responses to Staff data request DLH-3.10 based upon the Companies' rebuttal revenue requirements.

RESPONSE:

NS DLH 23.01 Attach 01 is an Excel file of the proposed Rider VBA rate case margins, customers and margin per customer by rate class based on the Company's rebuttal revenue requirements in this case.

The Peoples Gas Light and Coke Company
Docket No. 09-0167
Attachment to Staff Data Request DLH-23.01

Proposed Rider VBA Rate Case Margin per customer - 2010 - REBUTTAL Rates - Revisec

Description	2010 Jan	2010 Feb	2010 Mar	2010 Apr	2010 May	2010 Jun	2010 Jul	2010 Aug	2010 Sep	2010 Oct	2010 Nov	2010 Dec	Annual	Total
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Block 2	97,494,668	80,868,553	64,395,092	29,671,138	6,899,475	847,712	635,869	447,369	2,129,712	13,359,450	47,300,807	84,111,339	428,161,184	
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Distribution rate block 1	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896	$ 0.36896		
Distribution rate block 2	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665	$ 0.13665		
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Rate Case Margin per customer	$ 33.18	$ 30.12	$ 26.05	$ 19.22	$ 10.67	$ 7.54	$ 6.91	$ 6.51	$ 9.39	$ 13.81	$ 22.49	$ 30.27	$ 217.07	
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Distribution rate block 1	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638	$ 0.33638		
Distribution rate block 2	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376	$ 0.14376		
Distribution rate block 3	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596	$ 0.11596		
Distribution Revenue / Rate Case Margin														
Block 1	$ 2,525,728.40	$ 2,509,068.18	$ 2,515,150.93	$ 2,162,861.51	$ 1,509,027.93	$ 1,212,277.86	$ 1,161,373.81	$ 1,198,718.72	$ 1,358,521.09	$ 1,743,516.07	$ 2,080,690.94	$ 2,494,348.86	$ 22,471,284.30	
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