STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	**Docket No. 14-0224**
Proposed general increase in rates for gas distribution service	:	
	:	**(cons.)**
The Peoples Gas Light and Coke Company	:	
	:	**Docket No. 14-0225**
Proposed general increase in rates for gas distribution service	:	

INITIAL BRIEF OF THE STAFF OF THE ILLINOIS COMMERCE COMMISSION

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Staff of the Illinois Commerce Commission ("Staff"), by and through its counsel, pursuant to Section 200.800 of the Rules of Practice (83 Ill. Adm. Code 200.800) of the Illinois Commerce Commission's ("Commission"), respectfully submits its Initial Brief in the above-captioned matter.

I. INTRODUCTION

A. Overview/Summary

North Shore Gas Company ("North Shore" or "NS") and the Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL") (individually, the "Company" and collectively the "Companies", "Utilities", or "NS-PGL") filed new tariff sheets on February 26, 2014 in which the Companies proposed general increase in their natural gas rates. On March 19, 2014 the Companies' tariff sheets were suspended by the Commission and on July 19, 2014 the Commission entered a Re-suspension Order extending the suspension to and including January 25, 2015. In due course, the Administrative Law Judges ("ALJs") assigned to this proceeding established a schedule for the submission of pre-filed testimony, hearings and briefs. (*Tr.*, April 14, 2014, pp. 6-7)

In response to the Company's filing, the following parties filed Petitions to Intervene, which were granted: The People of the State of Illinois *ex rel.* Lisa Madigan, Attorney General of the State of Illinois (the "AG"); Environmental Law and Policy Center ("ELPC")[1]; Citizens Utility Board ("CUB"); the City of Chicago ("City"); the Illinois Industrial Energy Consumers (members: the Merchandise Mart, University of Illinois and Ford Motor Company)[2] and the Retail Energy Suppliers Association ("RESA")[3],

The following witnesses submitted testimony on behalf of Staff: Dianna Hathhorn (Staff Exhibit ("Ex.") 1.0 and Staff Ex. 6.0), Daniel G. Kahle (Staff Ex. 2.0, Staff Ex. 7.0); Janis Freetly (Staff Ex. 3.0, and Staff Ex. 8.0); and William R. Johnson (Staff Ex. 4.0 and Staff Ex. 9.0); and Brett Seagle (Staff Ex. 5.0 and Staff Ex. 10.0)

During the course of the proceeding, Staff proposed various adjustments and changes to the Companies' February 26, 2014 request. The Companies accepted certain of Staff's modifications, and Staff withdrew others. A summary of Staff's final recommendations to the Commission in this proceeding for North Shore and Peoples Gas are attached hereto, respectively, as Appendix A and Appendix B. Also, attached as part of Appendix A and Appendix B are Staff's revised Revenue Requirements. For

[1] The AG and ELPC sponsored the testimony of witness Scott J. Rubin jointly.

[2] The City, CUB and IIEC sponsored the testimony of Michael P. Gorman. The are jointly identified as CCI.

[3] RESA did not sponsor any witness testimony.

the reasons stated below, Staff's proposed adjustments should be adopted by the Commission.

II. TEST YEAR (Uncontested)

The Companies propose using their forecasted calendar year 2015 as the test year in this proceeding. (NS Ex. 5.0, p. 1; PGL Ex. 5.0, p. 1) Staff did not take issue with the Companies' selection of a 2015 test year.

III. REVENUE REQUIREMENT

The revenue requirement schedules attached to Staff's Initial Brief use the Peoples Gas' surrebuttal revenue requirement, and North Shore's rebuttal revenue requirement, as their starting point.[4] To the extent that Staff's proposed adjustments were rejected or only partially accepted by the Companies and reflected in the Companies surrebuttal revenue requirement, Staff's proposed adjustments are shown either in total or in part as an adjustment to the Companies' surrebuttal revenue requirement. Staff's proposed adjustments that were accepted in total by the Companies and therefore are reflected in the Companies' surrebuttal position are not shown as an adjustment on Staff's Initial Brief Revenue requirement schedules.

A. North Shore

Staff recommends a revenue requirement of $86,798,000 as reflected on page 1 of Appendix A to Staff's Initial Brief.

Staff recommends an increase to base rates of $3,460,000 and an increase of $84,000 to other revenues for a total increase of $3,544,000 (4.26%).

[4] North Shore did not submit a new revenue requirement in surrebuttal. (NS-PGL Ex. 36.0, 3.)

Staff's overall recommended increase is $2,980,000 less than the $6,524,000 increase requested by North Shore in rebuttal.

B. Peoples Gas

Staff recommends a revenue requirement of $667,945,000 as reflected on page 1 of Appendix B to Staff's Initial Brief.

Staff recommends an increase to base rates of $69,405,000 and an increase of $1,674,000 to other revenues for a total increase of $71,079,000 (11.91%).

Staff's overall recommended increase is $29,462,000 less than the $100,541,000 increase requested by Peoples Gas in surrebuttal.

C. Proposed Reorganization

Section 9-201(c) of the PUA provides in part that "[i]f the Commission enters upon a hearing concerning the propriety of any proposed rate or other charge, classification, contract, practice, rule or regulation, the Commission shall establish the rates or other charges, classifications, contracts, practices, rules or regulations proposed, in whole or in part, or others in lieu thereof, which it shall find to be just and reasonable." 220 ILCS 5/9-201(c). Based on the circumstances of the proposed merger and this proceeding's record described below, it is reasonable that (i) the Companies did not provide any information in this docket about future cost savings regarding the proposed merger and possible acquisition of the ultimate parent company of the Companies, Integrys Energy Group, Inc. ("Integrys"), by Wisconsin Energy Corporation ("WEC") ("Reorganization"); and (ii) the Companies' proposed rates, which are based upon 2015 test years, do not reflect future costs savings of the Reorganization. (Staff Ex. 6.0, 24-25.) In Staff's view, because the Reorganization is not guaranteed, and even if it is approved, the conditions and timing of its approval cannot be known; it is reasonable that future cost savings are not reflected in this rate proceeding.

The AG recommended that the Companies describe and quantify the expected operational and financial benefits of the Reorganization. (AG Ex. 1.0, 4-5.) Companies' witness Derricks responded generally that the Reorganization is subject to future regulatory approvals, and the conditions and timing are unknown. (NS-PGL Ex. 17.0, 10.) Since the filing of the Companies' rebuttal testimony, the Companies filed their Application for the Reorganization in Docket No. 14-0496. The Companies' responses to discovery concerning the Reorganization's effect on the 2015 test year revenue requirement are included in Attachment B to Staff Ex. 6.0.

Staff witness Hathhorn testified concerning the timing of the pending rate cases with the Reorganization and whether it was reasonable that the Companies' proposed rates do not reflect future costs savings from the Reorganization. (Staff Ex. 6.0, 24.) In the Fact Sheet filed in Docket No. 14-0496, as part of the filing requirements under Section 7-204A(a)(2)(ii) (Staff Ex. 6.0, Attachment B), Integrys states that the expected closing of the transaction is summer 2015. The Companies are not requesting cost recovery of the acquisition premium; i.e., the price above book value, or the costs incurred to accomplish the Reorganization, (Docket No. 14-0496, Petition, 13), although these costs are expected to be incurred within the 2015 test year. The Reorganization is expected to have potential long-term synergy savings. (Attachment B.) The Fact Sheet states further that the combination is accretive to earnings per share in the first full calendar year after closing, likely 2016 based on the expected closing date.

In light of the fact that the Reorganization is not guaranteed, and even if it is approved, the conditions and timing of its approval cannot be known; therefore, it is reasonable that future cost savings are not reflected in this rate proceeding. In addition, based on the information provided by the Companies as to their current expectations with respect to the Reorganization, it is also reasonable that the Companies' 2015 test years do not reflect future cost savings from the Reorganization due to the expected timing of the closing of the Reorganization and Integrys' expectation of savings and shareholder benefits to earnings occurring outside of the test year. (Staff Ex. 6.0, 24.) Under some circumstances, however, if the Reorganization is approved and savings are realized sooner than expected, the rates derived from this proceeding may need to be adjusted. (220 ILCS 5/9-250.) Further, should information become known that would materially change these expectations, the Commission has the authority to investigate the Companies' rates and/or enter a temporary order fixing a temporary schedule of rates under Article 9 and to condition its approval of the Reorganization on the appropriate sharing of savings or to require compliance with other conditions to reflect the Reorganization's impact on rates. (220 ILCS 5/9-202.)

Finally, based on the information provided by the Companies in this proceeding, Staff's finance expert witness, Janis Freetly, testified that there is no need to adjust Staff's recommended rate of return on rate base due to Wisconsin Energy Corporation's proposed acquisition of Integrys. At this time, it is unknown if the reorganization will occur and if so, how the reorganization will affect the Companies' rate of return. (Staff Ex. 8.0, 21.) Should information become known that would materially change the rate of return on rate base, however, the Commission has the authority to investigate the

Companies' rates under Article 9 as discussed above, and to condition its approval of the reorganization on a revised rate of return on rate base should the merger impact that set in this proceeding pursuant to Section 5/7-204(f) of the PUA. Id.

IV. RATE BASE

A. Overview/Summary/Totals

1. North Shore

Staff recommends a rate base of $218,599,000 as reflected on page 4 of Appendix A to Staff's Initial Brief. Staff's recommendation is $1,187,000 less than the $219,786,000 rate base requested by North Shore in rebuttal.

2. Peoples Gas

Staff recommends a rate base of $1,670,732,000 as reflected on page 4 of Appendix B to Staff's Initial Brief. Staff's recommendation is $88,557,000 less than the $1,759,289,000 rate base requested by Peoples Gas in surrebuttal.

B. Potentially Uncontested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted

1. Gross Utility Plant

a. 2013 Plant Balances[5]

b. 2014 Plant Balances (other than PGL AMRP Additions and associated items addressed in Section IV.C.1.a)

c. 2015 Forecasted Capital Additions

i. In General

ii. Calumet System Upgrade (PGL)

iii. Casing Remediation (PGL)

iv. Gathering System Pipe Replacement Project (PGL)

Staff witness Seagle recommended the Commission reduce Peoples Gas' requested O&M expense by $164,123 associated with its remediation project involving the replacement of plastic pipefittings. (Staff Ex. 5.0, 5.) In rebuttal, Peoples Gas agreed that it should remove the operating expenses associated with its plastic pipefitting remediation project from its requested rates. (NS-PGL Ex. 23, 2.) This issue is no longer contested.

v. LNG Control System Upgrade (PGL)

vi. LNG Truck Loading Facility (PGL)

Staff witness Seagle recommended the Commission reduce Peoples Gas' rate base, regarding a Liquefied Natural Gas 20 ("LNG") Truck Loading Facility, by $4,000,000. (Staff Ex. 5.0, 16.) In rebuttal, Peoples Gas withdrew its request for recovery of costs associated with the construction of a Liquefied Natural Gas ("LNG")

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5 The term plant balances as used in this outline includes Construction Work in Progress not accruing AFUDC.

Truck Loading Facility. (NS-PGL Ex. 30.0, 2.) Despite Peoples Gas' willingness to withdraw its request for cost recovery, Staff recommends the Commission require Peoples Gas to seek approval pursuant to Section 7-102 of the Public Utilities Act ("PUA") (220 ILCS 5/7-102) prior to initiating the construction of a LNG Truck Loading Facility or entering into contracts to sell LNG by means of the LNG Truck Loading Facility at its Manlove storage field complex.

In rebuttal, Peoples Gas witness Thomas Puracchio stated: "Peoples Gas reserves the right to construct and operate such a LNG Truck Loading Facility and to seek recovery through rates in the future." (NS-PGL Ex. 30.0, 1.) Staff reiterated its recommendation that Peoples Gas receive Commission approval pursuant to Article 7 of the Act to construct and operate the LNG Truck Loading Facility in Mr. Seagle's rebuttal testimony. (Staff Ex. 10.0, 5.) In surrebuttal, Mr. Puracchio stated that "the issue of what particular activities require Commission approvals are a legal matter and Peoples Gas shall address this issue in briefs rather than in testimony." (NS-PGL Ex. 44.0, 2.)

Section 7-102 (A) states:

> Unless the consent and approval of the Commission is first obtained or unless such approval is waived by the Commission or is exempted in accordance with the provisions of this Section or of any other Section of this Act (220 ILCS 5/7-102(A).)

Further, Section 7-102 (A)(g) states:

> No public utility may use, appropriate, or divert any of its moneys, property or other resources in or to any business or enterprise which is not, prior to such use, appropriation or diversion essentially and directly connected with or a proper and necessary department or division of the business of such public utility; provided that this subsection shall not be construed as modifying subsections (a) through (e) of this Section. (220 ILCS 5/7-100 102(A)(g).)

Section 7-102 (A) requires Commission consent and approval prior to a utility doing anything outlined in subsections (a) through (h) unless waived or exempted. Section 7-102 (A)(g) requires that, among other things, utilities only use their property in a manner which is directly related to the business of providing utility services. The purpose of these provisions of the Act is to assure both that ratepayers are adequately served by the utility and that the utility receives reasonable return for its services. Village of Hillside v. Ill. Commerce Comm'n, 111 Ill.App.3d 25 (1st Dist. 1982).

Peoples Gas wants to construct a $4,000,000 facility that would allow it to load tanker trucks with LNG from its LNG facility. Peoples Gas' LNG facility is located at its Manlove Underground Gas Storage Field ("Manlove") near Fisher, Illinois. Peoples Gas wants to sell LNG to LNG marketers via tanker trucks from Manlove. (Staff Ex. 5.0, 6.) In Direct Testimony, Mr. Seagle expressed concern for this proposal because the Company did not provide: an update on the status of the business case review, the detailed costs estimate, and management approval; evidence of executive approval of the project; documentation necessary to demonstrate the prudence of Peoples Gas' decision to proceed with the project; studies demonstrating a benefit or need for the project, including any contracts with LNG marketers or letters of intent from companies that intend to purchase LNG from Peoples Gas; or any evidence that Peoples Gas could reasonably expect to acquire LNG from some other nearby source in a timely manner, truck it to Manlove, and unload it into the LNG facility at volumes that would make this option of natural gas supply to its customers viable. (Staff Ex. 5.0, 17.) Peoples Gas did not respond to these requests; rather the Company simply withdrew its request for $4 million cost recovery. Most importantly, the Company did not provide any evidence that selling LNG to LNG marketers is "essentially and directly connected with or a proper and necessary department or division of the business of such public utility" as described in Section 7-102(A)(g) of the Act. Peoples Gas diverting $4,000,000 from utility operations to construct a facility that would allow it to load tanker trucks with LNG from its LNG facility certainly could have an impact on Peoples Gas ability to adequately serve its customers. For that reason alone, Peoples Gas should be ordered to seek approval from the Commission before following through on its plans.

Finally, if the Commission agrees with Staff's recommendation regarding the LNG Truck Loading Facility, Staff recommends this language in the Final Order:

> The Commission directs Peoples Gas to file a petition pursuant to Section 7-102 of the PUA (Transactions requiring Commission approval) requesting approval for the construction and operation of a LNG Truck Loading Facility for the solicitation of LNG to non-utility customers prior to Peoples Gas or any of its affiliates initiating the construction of a LNG Truck Loading Facility or entering into contracts to sell LNG by means of the LNG Truck Loading Facility at its Manlove storage field complex.

vii. Reclassification of Costs to Plant in Service (PGL)

viii. Wildwood/Gages Lake (NS)

ix. Grayslake Gate Station (NS)

x. Casing Remediation (NS)

xi. Locker Room (NS)

Staff witness Seagle recommended the Commission reduce North Shore's rate base, regarding a Locker Room Replacement Project by $200,000. (Staff Ex. 5.0, 22.) In rebuttal, North Shore Gas agreed to withdraw its request to recover costs associated with the Locker Room Replacement Project at North Shore's Waukegan facility. (NS-PGL Ex. 31.0, 2.) This issue is no longer contested.

d. Original Cost Determinations as to Plant Balances as of December 31, 2012

Staff and the Companies agree that the Commission's Order should state the following with respect to the Original Cost Determination:

> It is further ordered that the $443,539,000 original cost of plant for North Shore at December 31, 2012 and the $3,285,370,000 original cost of plant for Peoples Gas at December 31, 2012, as presented in Staff Exhibit 1.0, are unconditionally approved as the original costs of plant. (NS Ex. 7.0, 14; PGL Ex. 7.0, 17)

(Staff Ex. 6.0, 29-30)

2. Accumulated Provisions for Depreciation and Amortization (including new depreciation rates and including derivative impacts other than in Section IV.C.1.a)

3. Cash Working Capital (other than Section IV.C.2)

4. Materials and Supplies, Net of Accounts Payable

5. Gas in Storage

6. Budget Plan Balances

7. Accumulated Deferred Income Taxes

a. Incentive Compensation

b. Net Operating Losses

c. Derivative Impacts (other than in Section IV.C.1.a)

8. Customer Deposits

9. Customer Advances for Construction

10. Reserve for Injuries and Damages

11. Other

C. Potentially Contested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Plant

a. 2014 AMRP Additions (including derivative impacts on Accumulated Depreciation and Accumulated Deferred Income Taxes) and Associated Cost of Removal (PGL)

Staff recommends the Commission adopt the AG's revised adjustment to Peoples Gas' 2014 Accelerated Main Replacement Program ("AMRP") additions that also qualify as Rider QIP ("Qualifying Infrastructure Plant") additions, so that rate base is set at a reasonable level, rather than the Company's forecast which appears unattainable. (AG Ex. 7.0, 2-6)[6] As discussed in the Rider QIP Recommendations Section IX.D.2.c., the amount of AMRP additions included in rate base in the instant proceeding will be adjusted to actual costs through the Rider QIP surcharge.[7] (PGL Ex. 1.0, 5-6) Therefore, the primary impact of the 2014 AMRP Additions adjustment will be its impact on base rate revenues for purposes of the future Rider QIP cap, discussed below.

While the Company did reduce its 2014 forecasted additions for AMRP and the Calumet Pipeline Project in rebuttal testimony (NS-PGL Ex. 23.0 2nd REV., 4-5), the record shows that the Company's forecast is still not reasonable. As shown below, Peoples Gas has added approximately $51 million in additions through August 2014; it would need to place in service additionally more than double that amount in September through December 2014 in order to attain its forecast of $173 million. In addition, using the latest available information, the Company would have to invest more than $100 million in just three months to hit its forecast[8], A summary of the final positions of the parties and the record is as follows:

Table 1: 2014 QIP in Rate Base	Gross Utility Plant (Rider QIP Additions less Retirements)	Source
Peoples Gas	$173,237,522	NS-PGL Ex. 22.14 P, 1

[6] The Company provided corrections to Mr. Effron's adjustment, as recommended by Staff, and the AG did not object. (Staff Ex. 6.0, 20; NS-PGL Ex. 37.5P) Staff's Initial Brief Appendix B reflects adoption of the AG's position, as corrected by the Company.

[7] Rider QIP is comprised primarily of plant additions for the Accelerated Main Replacement Program, however other additions are also allowed. (220 ILCS 5/9-220.3 (b))

[8] Staff filed a motion for the Commission to take administrative notice of the most current information regarding rider QIP investment, subsequent to the evidentiary hearings. Staff's motion has not been ruled upon yet.

AG (as corrected by Peoples Gas and adopted by Staff)	$115,986,348	NS-PGL Ex. 37.5 P, 1
Actual through Aug. 2014	$ 51,411,661	Staff Group Cross Ex. 1, DLH 34.02, Attach 1, p. 26, col. [C]
Actual through Sept 2014	$72,647,285	PGL Advice No. 1522, Dated October 15, 2014, Rider QIP Information Sheet No. 9, p. 26, col. [C].

Rider QIP contains a revenue cap at Section 9-220.3(g), which limits increases billed under Rider QIP to an annual average of 4% of base rate revenue, not exceeding 5.5% in any given year. (Staff Ex. 6.0, 18.) The Company is concerned that if the appropriate 2014 AMRP additions amount is not included in the approved base rate revenue, the amount of QIP investment that can be recovered under Rider QIP after new rates become effective as a result of this proceeding (2015 and subsequent years) will be impacted.(NS-PGL Ex. 43.0 REV.) Staff emphasizes that everything from this case which impacts base rate revenues will affect the new Rider QIP revenue cap, not just the level of Rider QIP additions allowed in rate base. (Staff Ex. 6.0, 18.) Further, the existence of the cap is not adequate justification to allow rates that include an unreasonable amount of rate base. Base rate revenues should determine the cap. The Company's position would flip that and have the cap determine base rate revenues. This proposal by the Company is neither just nor reasonable.

2. Cash Working Capital

a. OPEB lead

Staff and the Companies agree on the methodology to update Cash Working Capital ("CWC") for the final revenue requirements ordered by the Commission in the instant cases, and for all leads and lags except for the expense lead for pension and other post employment benefits ("OPEB"). Appendices A and B to Staff's Initial Brief, p. 12 for both Companies, use an OPEB payment date in December, rather than January as used by the Companies, because the OPEB December payment date appears more reasonable in light of past payments by the Companies. This results in an OPEB positive lead of 170.00 days in the CWC calculation for North Shore, rather than a negative expense lead of (66.64) days; and a positive lead of 169.91 days in the CWC calculation for Peoples Gas, rather than a negative expense lead of (99.06) days, because it is not reasonable to base the 2015 future test year on the early payment date that occurred in 2012.

The Companies opine that since the OPEB payments do not have a statutory due date, a payment cannot be deemed early or late. (NS-PGL Ex. 37.0, 5) Staff disagrees. The undisputed evidence shows the historical OPEB payment activity:

Year	Largest OPEB Payment Date[9]
2009	December
2010	December (payment made by trust, not Companies)
2011	February
2012	January
2013	December
2014	Not yet paid

(Staff Ex. 6.0, 7)

[9] 2009 and 2010: Companies' Response to Staff DR DLH 30.05; 2011: NS-PGL Ex. 22.15; 2012-2014: Staff Ex. 1.0, 9-10: 195-201 and Attachment A.

Staff's position is that basing the expense lead for OPEB in the CWC calculation based upon the Companies' past payment practice for OPEB for one of the last six years is not prudent or reasonable. (Staff Ex. 6.0, 8) The early OPEB trust fund payments of $7.5 million for North Shore and $67.5 million for Peoples Gas, combined with the payment made so early in the calendar year, actually creates a negative lead or a revenue lag. Therefore, the Companies' position creates a higher CWC and rate base than is necessary when using their customary payment practice. (Staff Ex. 1.0, 9)

The Commission has previously ruled that CWC and rate base should not be increased when utilities pay expenses earlier than necessary. For instance, in Docket No. 13-0192, Ameren Illinois Company ("AIC") proposed that the expense leads for its pass-through taxes be set based on the amount of time AIC holds the funds before remittance. However, in Docket 13-0192, Staff and the AG and CUB proposed that the calculation be instead based on when the taxes are due, consistent with prior Commission Orders in Docket Nos. 12-0001, 12-0293, 11-0721, and 12-0321. The Commission agreed with Staff, the AG and CUB:

> The Commission agrees with Staff and AG/CUB that their proposal is consistent with recent Commission Orders and will protect ratepayers from incrementally higher rates attributable to the utility's practice of remitting taxes earlier than they are due. As Staff points out, AIC's practice of remitting pass-through taxes earlier than required increases rate base by increasing CWC

Ameren Illinois Company, ICC Order Docket No. 13-0192, 19 (December 18, 2013).

The AIC Order addressed pass-through taxes having a statutory due date while in this proceeding, the OPEB payments do not have a statutory due date. But, like AIC, the Companies are proposing an earlier payment date than required that unnecessarily and unreasonably increases rate base. Since the OPEB trust fund payments do not have a set due date, the CWC factor should be based on the Companies' normal payment policy date of December, consistent with the Commission's position that early payments should not result in increased rate base to rate payers. (Staff Ex. 1.0, 10-11, Staff Ex. 6.0, 8)

3. Retirement Benefits, Net

In summary, disallowances from rate base for the Companies pension assets and related accumulated deferred income taxes ("ADIT") are required since the Companies have not demonstrated that they were created with anything other than ratepayer funds. (Staff Ex. 6.0, Schs. 6.09 N and P.[10]) Staff's position is in accordance with multiple Commission orders, in which the Commission has repeatedly held that shareholders are not entitled to a return on ratepayer-supplied funds. The Companies' criticisms of prior orders of the Commission and Appellate Court discussed below do not diminish those rulings. Staff presents its understandings of the full set of Companies' objections to its adjustments below.

Prior Commission orders and the Appellate Court ruling are still authoritative.

Peoples Gas acknowledges that the Commission ruled that its pension asset should not be included in rate base in its last four general rate cases, but continues to believe that inclusion of its pension asset in rate base is warranted. North Shore has

[10] While North Shore forecasts a pension liability at December 31, 2015 (NS-PGL Ex. 26.0, 8), since North Shore's rate base is an average rate base, the balances at December 31, 2014 and December 31, 2015 are used to determine the average for the 2015 test year.

not had a pension asset in the last four rate cases. (PGL Ex. 12.0, 14: 303-310; NS Ex. 12.0, 14: 303.)

The Companies generally reject the Commission's prior holdings that the pension asset was created with ratepayer funds. The specifics of the Companies' position in this case have been presented and rejected several times in the past. Peoples Gas states that its additional grounds for inclusion in rate base in its Docket Nos. 12-0511/12-0512 ("2012 rate case") were not explicitly addressed by the Commission's final Order. Id. Peoples Gas mischaracterizes the Commission's final Order in its 2012 rate case. The Commission's Order specifically sets forth all of Peoples Gas' claims for its position (<u>North Shore Gas Company and The Peoples Gas Light and Coke Company</u>, ICC Order Docket Nos. 12-0511/12-0512 (Cons.), 80-82 (June 18, 2013)) and the Commission's conclusion shows that it rejected those claims. (Id., 90) The Commission is not required to make a particular finding as to each evidentiary fact or claim made by a party. (United Cities Gas Co. v. Illinois Commerce Commission, 47 Ill.2d 498, 501 (1970)

Peoples Gas criticizes Staff's reliance on the Appellate Court decision arising out of Docket Nos. 09-0166/09-0167 Cons. ("2009 Court Opinion") because the Commission and Court did not specifically refute all the Company's points made in Docket Nos. 11-0280/11-0281 ("2011 rate cases") or the 2012 rate cases. (NS-PGL Ex. 26.0, 9-10: 191-206.) However, while there are still appeals outstanding on the 2011 and 2012 rate cases, the 2009 Court Opinion which rejected the Company's pension asset arguments is still good law.

The evidence shows that the pension assets were created with funds supplied by ratepayers, not shareholders. Therefore, shareholders are not entitled to earn a return on them.

The evidence presented by the Companies in this case simply does not distinguish this case from prior Commission rulings on the same subject. (See generally, Staff Ex. 1.0, 12-23.) The Companies provided no evidence that the contributions were made from any source other than normal operating revenues (i.e. direct unequivocal contributions from shareholders creating a "pension asset"). The Companies state only that contributions to the pension plan "would be first funded from operating cash flows. If operating cash flows are insufficient, the cash requirements are funded with short-term debt; short-term debt would be replaced as needed by long-term debt and equity to maintain our capital structure. Thus contributions are ultimately funded by capital." (Attach. B to Staff Ex. 1.0)

Prior orders reject any inclusion of a pension asset in rate base for anything other than a specific contribution from shareholders. In Docket Nos. 09-0166/09-0167 (Cons.), the Commission denied inclusion of Peoples Gas' pension asset in rate base since there was no evidence in the record it was created with shareholder funds:

> The Utilities have given us no reason to overturn our decision from their last rate case. Although the Utilities state that the pension asset was created with shareholder funds, no evidentiary support was provided. **The Commission finds no support in the record to allow for the inclusion of Peoples Gas' pension asset in rate base which in turn would allow shareholders to earn a return on ratepayer supplied funds.** North Shore Gas Company and The Peoples Gas Light and Coke Company, ICC Order Docket Nos. 09-0166/09-0167 (Cons.), 36 (January 21, 2010) (emphasis added).

The Illinois Appellate Court upheld this order, stating:

> **The central issue before us remains whether the Commission's decision to exclude the pension asset, which it**

> **found consisted of consumer-supplied funds, from Peoples Gas' rate base was against the manifest weight of the evidence.** Both the Staff's and the People's expert witness testified the pension asset constituted customer-supplied revenues and, therefore, should be deducted from the rate base calculation.
>
> …
>
> Based on the record before us, we find the **Commission's decision with regard to the pension asset deduction is not clearly against the manifest weight of the evidence. Accordingly, we see no reason to disturb the Commission's findings.** *Peoples v. Illinois Commerce Commission*, Nos. 1-10-0654, 1-10-0655, 1-10-0936, 1-10-179, and 1-10-1846 and 1-10-1852, Consolidated, Appellate Court (First District-Fifth Division) September 30, 2011, at 42-43, par. 69-71 (emphasis added).

The Commission again denied inclusion of the pension asset in the subsequent two North Shore/Peoples Gas rate cases. See generally, North Shore Gas Company and The Peoples Gas Light and Coke Company, ICC Order Docket Nos. 11-0280/11-0281 (Cons.), 33 (January 10, 2012); North Shore Gas Company and The Peoples Gas Light and Coke Company, ICC Order Docket Nos. 12-0511/12-0512 (Cons.), 90 (June 18, 2013).

In three separate gas rate cases, Docket No. 08-0363[11], Docket No. 04-0779,[12] and Docket No. 95-0219,[13] Northern Illinois Gas Company d/b/a Nicor Gas Company sought to increase utility rate base for the amount of a prepaid pension asset. In all three cases, the Commission found that the pension asset was created by ratepayer-supplied funds, not by shareholder-supplied funds. The Commission concluded that ratepayers should not be denied the benefits associated with the previous overpayment

[11] ICC Order Docket No. 08-0363, Final Order at 18 (March 25, 2009).

[12] ICC Order Docket No. 04-0779, Final Order at 22-23 (September 20, 2005).

[13] ICC Order Docket No. 95-0219, Final Order at 9 (April 3, 1996).

for pension expense which ratepayers funded. Accordingly, the Commission concluded that the pension asset should be eliminated from rate base.

Likewise, in Docket No. 11-0767, the Commission ruled that Illinois American Water Company's proposal to include a pension asset in rate base was not substantively different than those the Commission had considered, and rejected, in past rate case decisions.[14]

Therefore, the only time the Commission has allowed a return on pension plan payments was the identification of a specific contribution from shareholders, not a theoretical contribution as the Company argues here. (Staff Ex. 6.0, 12.) It is undisputed that the Company has an expected pension contribution of $0 for the test year. (Id.; NS-PGL Ex. 26.0, 6:111.) Additionally, the return on the specific pension payment previously approved by the Commission was a debt return, not the cost of capital. Commonwealth Edison Company, ICC Order Docket No.05-0597 (Order on Rehearing), 28-29 (December 20, 2006). Also, while the Electric Infrastructure Investment and Modernization Act ("EIMA") does allow an investment return on a pension asset recorded in FERC Account 186 to be included in rates, that is specifically authorized in EIMA and does not apply to Peoples Gas. (16-105.5(c)(4)(D)).

Lowered pension expense was created from ratepayer supplied funds.

The Companies state, "The more cash Peoples Gas [or North Shore] contributes into the trust, the lower the pension costs that Peoples Gas [or North Shore] has to record and ultimately recover from customers through rates." (PGL Ex. 12.0, 16: 348-350; NS Ex. 12.0, 16: 340-342.) This argument fails to acknowledge that the

[14] ICC Order Docket No. 11-0767, Final Order at 8 (September 19, 2012).

Companies will receive the full amount of actuarially determined pension expense in the revenue requirement. In other words, Staff's proposed adjustments do not disallow the costs for the annual pension expense. Further, Peoples Gas states that it made no contributions into the qualified pension plan during 2013 and 2014, (PGL Ex. 12.0, 7: 148-149) and the Companies updated actuarial reports reflect zero employer contributions for the year 2015 for both utilities. (NS-PGL Ex. 26.0, 6:111.) Therefore, Staff's adjustments, which do not affect the amount to be recovered by the Companies in operating expenses, would have no effect on future pension contributions.

Exclusion of a pension asset from rate base does not mean excluding a pension or OPEB liability is reasonable.

The Companies state that their argument for pension asset inclusion in rate base would be consistent with the current exclusion of their OPEB liabilities from rate base (”symmetry argument”). The Companies' position to include pension assets in rate base has no bearing on the proper exclusion of an OPEB liability from rate base.

OBEB liabilities represent other post-employee benefits that had not been paid out to the OPEB trust by the end of the year and for which the utility has already received recovery from rates. Rate base is properly reduced by these OPEB liabilities to recognize that such costs are already recovered from ratepayers by their inclusion as an operating expense. It would not be reasonable to allow shareholders a return on this cost-free source of capital to the Companies. The Companies' symmetry argument does not take this into account. (Staff Ex. 1.0, 19) The Commission has also rejected the Companies' symmetry argument in the past.

In Docket Nos. 07-0241/07-0242 (Cons.) both Peoples Gas and North Shore excluded their OPEB liabilities from rate base, i.e., neither utility reduced rate base for the OPEB liabilities. Peoples Gas also had a pension asset, which the Company did not include in rate base. Peoples Gas argued for symmetrical treatment; that is, excluding both its pension asset and OPEB liability from rate base. The Commission instead found that the pension asset should be excluded from rate base and that the OPEB liabilities should be reflected as a reduction to rate base:

> The Commission agrees with the positions asserted by GCI and Staff. Their arguments are persuasive and fully supported by the evidence. Further, they have each established that the treatment we are being urged to assign to this item today, is the same the treatment that we adopted in a number of previous decisions. On all these grounds, **the Commission accepts that a rate base deduction of $7,094,000 ($4,074,000 net of related deferred taxes) is required for the North Shore accrued OPEB liability and a rate base deduction of $55,653,000 ($31,570,000 net of related deferred taxes) is required for the Peoples Gas accrued OPEB liability in the determination of the Utilities' rate bases.** *See* GCI Ex. 2.0 at 13.
>
> **Further, we note that the underlying rationale for these adjustments is that such funds are supplied by ratepayers and not by shareholders such that shareholders are not entitled to earn a return on these funds. Accordingly, the undisputed record showing that Peoples Gas and North Shore contributed $15,278,614 and $1,862,247, respectively, to the pension plans during the test year, does not change the treatment of the OPEB liability. Nor are we convinced that such contributions should impact shareholders, given that these funds were provided by ratepayers through the collection of utility revenues**. We observe no discussion of or opposition to this particular recalculation that the Utilities propose on basis of their contribution, however, it appears to the Commission that recognizing these contributions is inconsistent with, the theoretical basis that we are applying here, i.e., these contributions are ratepayer-funded.
>
> **The Commission finds that the Utilities' OPEB liabilities will be deducted, and, for the reasons provided by Staff, Peoples Gas' contributions of $15,278,614 and North Shore's contributions of $1,862,247 to the pension plan should not be incorporated into the calculation of the rate bases.**

North Shore Gas Company and The Peoples Gas Light and Coke Company., ICC Order Docket Nos. 07-0241/07-0242 (Cons.), 36 (February 5, 2008) (emphasis added).

The Commission ruled in the same manner in the last two North Shore/Peoples Gas cases, Docket Nos. 11-0280/11-0281 (Cons.) and Docket Nos. 12-0511/12-0512 (Cons.):

> The Commission agrees with both Staff and GCI concerning the adjustments to rate base made to account for net retirement benefits. Staff witness Ebrey agreed with GCI witness Effron's approach which removed the Utilities' respective net pension assets from rate base, but kept the OPEB liabilities in rate base. Staff and GCI's adjustments are supported by the evidence and remain consistent with the Commission's conclusions about the pension asset in the 2007 and 2009 PGL rate cases. **Those decisions both concluded that the accrued OPEB liability should be reflected in rate base but that the pension balances should not be recognized in the determination of rate base.**

North Shore Gas Company and The Peoples Gas Light and Coke Company., ICC Order Docket Nos. 11-0280/11-0281 (Cons.), 33 (January 10, 2012) (emphasis added).

> The Commission finds that the Utilities' pension assets should not be included in rate base for the reasons stated in its past Orders. The Commission concludes, however, that the OPEB liabilities should be included in rate base, to be consistent with the prior rulings on the pension assets.

North Shore Gas Company and The Peoples Gas Light and Coke Company., ICC Order Docket Nos. 12-0511/12-0512 (Cons.), 90 (June 18, 2013).

In surrebuttal testimony, Peoples Gas states that if its pension asset is not included in rate base, then North Shore's pension liability should not be included. (NS-PGL Ex. 26.0, 10: 215-216.)[15] Similar to OPEB liabilities, the Companies' position to include pension assets in rate base has no bearing on the proper exclusion of a pension

[15] As discussed above, North Shore also includes a pension asset in its calculation of average rate base.

liability from rate base. Pension liabilities represent pension costs that have not been paid out to the pension trust by the end of the year but for which the utility has already received recovery through rates. Rate base is properly reduced by these pension liabilities to recognize that such costs are already recovered from ratepayers by their inclusion as an operating expense. It would not be reasonable to allow shareholders a return on this cost-free source of capital to the Companies. (Staff Ex. 6.0, 11.)

Ownership of the pension assets does not require inclusion in rate base.

The Companies state the pension assets are included in their balance sheets and that the Companies own the assets via the trusts that hold the assets. (PGL Ex. 12.0, 14: 312-315; NS Ex. 12.0, 14: 307-311.) However, it is not relevant who owns the assets of the pension trust fund. That is, ownership is not determinative of ratemaking treatment. For example, contributed plant may be owned by a utility, but a utility does not get a return on contributed plant from a customer. The determining question is whether the pension assets were created with funds from shareholders or ratepayers. As discussed above, no evidence of outside discreet shareholder funding of the pension contributions has been presented by the Companies. (Staff Ex. 1.0, 22.)

Under Illinois law for ratemaking purposes, a public utility may not receive a return on investment from ratepayers for ratepayer-supplied funds, and the Commission has consistently rejected the attempts of utilities to receive a return on ratepayer-supplied funds.

As noted above, a large number of Commission orders have concluded that financing a pension asset with internally generated funds does not permit a utility a rate base return on that asset. To put it simply, the Company is seeking to collect monies from ratepayers and then charge those ratepayers with a return on investment of those monies. What is relevant is that under Illinois law for ratemaking purposes a public utility may not receive a return on investment from ratepayers for ratepayer-supplied funds. City of Alton v. Illinois Commerce Comm'n, 19 Ill. 2d 76, 85-6, 91 (1960); DuPage Utility Co. v. Illinois Commerce Comm'n, 47 Ill. 2d 550, 554, 558 (1971); Central Illinois Light Co. v. Illinois Commerce Comm'n, 252 Ill. App. 3d 577, 583 (3rd Dist., 1993); see also, Business and Professional People for the Public Interest v. Illinois Commerce Comm'n ("BPI II"), 146 Ill. 2d 175, 258 (1991). The Commission has consistently rejected the attempts of other utilities to receive a return on ratepayer-supplied funds and should do so again here. See, Citizens Utility Board v. Illinois Commerce Comm'n, 166 Ill. 2d 111, 132 (1995) (Commission is unauthorized to depart drastically from practices established in earlier orders); Mississippi River Fuel Corp. v. Illinois Commerce Comm'n, 1 Ill. 2d 509, 514 (1953) (long-term consistent actions by the Commission are entitled to great weight and may be equal in force to a judicial construction).

Therefore, for all the reasons stated above, Staff recommends a disallowance of the Companies' pension asset and related ADIT from rate base.

V. OPERATING EXPENSES

A. Overview/Summary/Totals

1. North Shore

Staff recommends total operating expenses before income taxes of $67,000,000 as reflected on page 1 of Appendix A to Staff's Initial Brief.

2. Peoples Gas

Staff recommends total operating expenses before income taxes of $506,894,000 as reflected on page 1 of Appendix B to Staff's Initial Brief.

B. Potentially Uncontested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Other Revenues

2. Resolved Items

a. Incentive Compensation

Staff proposed adjustments to the Companies' operating expenses and rate base for incentive compensation expenses. The adjustments eliminated incentive compensation related to Executive Incentive Plan costs related to shareholder-oriented goals, Company affiliate-performance goals, and goals tied to financial performance; and Omnibus Incentive Compensation Plan costs related to shareholder-oriented goals. Staff contended that the Companies did not demonstrate that these costs provide tangible net benefits to ratepayers in order to prove that the recovery of these incentive compensation costs is just and reasonable. (Staff Ex. 2.0, 20.)

Staff's proposed adjustments were among several that the Companies accepted or did not contest in order to narrow the contested issues. (NS-PGL Ex. 21.0, 5-6; NS-PGL Ex. 24.0, 5; and NS-PGL Ex. 22.0, 5.)

Interveners also proposed adjustments related to the Companies' incentive compensation expenses. (AG Ex. 1.0, 24-26; CUB/City/IIEC Ex. 1.0, 55-58.) The interveners' adjustments are similar in rationale to those proposed by Staff; however, Staff's adjustments are consistent with the methodology accepted by the Commission in the Companies' recent rate cases. (NS-PGL Ex. 24.0, 5.)

b. Executive Perquisites

Staff proposed adjustments to remove executive perquisites that the Companies indicated provided reimbursements to five executive officers for personal benefits. (Staff Ex. 2.0, 10-11.)

The Companies accepted Staff's adjustment to remove certain executive perquisites and included Staff's proposed adjustment in their rebuttal testimony. The Companies, however, correctly used amounts forecasted for 2015 in the adjustment rather than the 2013 amounts Staff had proposed. (NS-PGL Ex. 21.0, 13-14.) Staff agreed with the Companies' modified adjustment. (Staff Ex. 7.0, 2.)

c. Interest

i. Budget Payment Plan

The parties are in agreement that the 0.0% interest rate set by the Commission on customer deposits should be used to calculate interest expense on Customer Deposits. (Order, Docket No. 13-0695, December 18, 2013, p. 1; NS-PGL Ex. 21.0, 5)

ii. Customer Deposits

The parties are in agreement that the 0.0% interest rate set by the Commission on customer deposits should be used to calculate interest expense on Customer Deposits. (Order, Docket No. 13-0695, December 18, 2013, p. 1; NS-PGL Ex. 21.0, 5)

iii. Synchronization (including derivative adjustments)

d. Lobbying

Staff proposed to reduce the Companies' test year operating expenses for lobbying related membership dues. (Staff Ex. 2.0, 16.) Staff's proposed adjustments were among several that the Companies accepted or did not contest in order to narrow the contested issues. (NS-PGL Ex. 21.0, 5-6.)

e. Fines and Penalties

Staff proposed an adjustment to remove fines and penalties from Peoples Gas' revenue requirement. Staff's proposed adjustment was among several that the Companies accepted or did not contest in order to narrow the contested issues. (NS-PGL Ex. 21.0, 5-6.)

f. Plastic Pipefitting Remediation Project (PGL)

3. Other Production (PGL)

4. Storage (PGL)

5. Transmission

6. Distribution

7. Customer Accounts – Uncollectibles

8. Customer Accounts – Other than Uncollectibles

9. Customer Services and Information

10. Administrative & General (other than items in Section V.C)

11. Depreciation Expense (including derivative impacts other than in Section IV.C.1.a)

12. Amortization Expense (including derivative impacts)

13. Rate Case Expense (other than amortization period in Section V.C.4)

Staff and the Companies agreed on the total amount of rate case costs. (Staff Ex. 7.0, 2.) As discussed below, Staff and the Companies do not agree on the amortization period and the resulting amount of rate case expenses. (Staff Ex. 7.0, 13.) Based on the amortization period discussed in Section V.C.4, Staff recommends that the Order in this proceeding express a Commission conclusion as follows:

> The Commission has considered the costs expended by the Companies to compensate attorneys and technical experts to prepare and litigate these rate case proceedings and assesses that the total rate case costs for these proceedings of $1,947,000 and $2,945,000 for North Shore and Peoples Gas, respectively, which are amortized over 2 and a half years and included as rate case expenses in the revenue requirements of $779,000 and $1,178,000 for North Shore and Peoples Gas, respectively, are just and reasonable.

(Staff Ex. 7.0, 16-17.)

14. Taxes Other Than Income Taxes (including derivative impacts)

15. Income Taxes (including derivative impacts)

Staff proposed adjustments to remove previously disallowed capitalized incentive compensation costs from the Companies' accumulated deferred income taxes ("ADIT") and to adjust ADIT related to net operating losses. (Staff Ex. 2.0, 25.) The Companies' accepted Staff's adjustments to ADIT. (NS-PGL Ex. 22.0, 2.)

16. Reclassification of Costs to Plant in Service (PGL)

17. Gross Revenue Conversion Factor

18. Other

a. Invested Capital Tax

Staff offered adjustments to Invested Capital Tax ("ICT") based on Staff's revenue requirement. (Staff Ex. 2.0, 26.) There are no contested issues concerning the calculation of ICT. (Staff Ex. 7.0, 13.) Staff and the Companies use the same methodology to compute ICT based on their own revenue requirements.

C. Potentially Contested Issues (All Subjects Relate to NS and PGL Unless Otherwise Noted)

1. Test Year Employee Levels

a. Peoples Gas

The Commission should reject AG witness Effron's (AG Ex. 1.0, 15-17.) and CUB/City/IIEC witness Gorman's (CUB/City/IIEC Ex. 1.0, 53-55.) proposals to reduce the number of projected test-year employees based on analyses of historical trends. While their analyses are logical to some extent, their arguments do not consider the Companies' recent hiring and do not refute the Companies' testimony regarding planned additional hiring. (Staff Ex. 7.0, 18.)

b. North Shore

Please see the discussion of the same topic for Peoples Gas above in section C.1.a.

2. Medical Benefits

a. Peoples Gas

b. North Shore

c. IBS

The Commission should reject AG witness Effron's proposed adjustment to reduce the amount of projected direct medical benefit costs and medical benefits allocated from IBS based on applying an inflation factor to historical costs. (AG Ex. 1.0, 17-20.) Mr. Effron's linear analysis does not allow for consideration of the Companies' projected increases in the number of employees or the Companies' independent study of claims. (NS-PGL Ex. 26.0, 9-11.)

Should the Commission determine to reduce the number of projected test-year employees, however, there should be a related reduction in projected direct medical benefit costs.

3. Other Administrative & General

a. Integrys Business Support Costs

i. Labor

The Commission should reject AG witness Effron's proposed adjustment to reduce the amount of IBS O&M cross charges for labor for both utilities. Mr. Effron's analysis increases historical costs by a general wage increase factor. (AG Ex. 1.0, 20-24.) The Companies demonstrate three factors that account for the additional increases: an increase in direct charges from IBS related to increased services; an increased number of employees; and a change in the allocation percentages based on the increased number of employees and total spending. (NS-PGL Ex. 27.0, 3-5.) While Mr. Effron's analysis is logical, it does not refute the Companies' testimony supporting the increases.

Should the Commission determine to reduce the number of projected test-year employees, however, there should be a related reduction to cross charges for labor for both utilities.

ii. Benefits

The Commission should reject AG witness Effron's proposal to apply allocation percentages from 2013 to 2015 projected costs. (AG Ex. 1.0, 29-30.) Percentages used to allocate 2015 projected costs should be based on the allocation base, such as the number of employees, approved by the Commission, for the period in which the costs are incurred. (Staff Ex. 7.0, 20.)

iii. Postage

The Commission should reject AG witness Effron's proposal to reduce postage expense charged to the utilities from IBS. (AG Ex. 1.0, 31.) Mr. Effron considers the amount of the proposed increase to be unreasonable, but does not make an argument against the Companies' rationale for the proposed increase. (AG Ex. 1.0, 30-31.) The Companies propose increasing postage expense because of an expected increase in the volume of mailings as well as a postage rate increase. (NS-PGL Ex. 27.0, 5-6.) The Companies' rationale is reasonable based on the support provided for the increase.

iv. Legal (NS)

The Commission should adopt Mr. Effron's proposed adjustment to legal expenses. AG witness Effron proposes to reduce projected legal expenses for North Shore. Mr. Effron cites not only to historical trends, but also to the lack of a defined rationale for the projected increase. (AG Ex. 1.0, 31-32.)

v. ICE Project

(a) Return on Assets and Depreciation

(b) Non-Labor

Staff does not support the AG proposed adjustments for the Companies' return on assets ("ROA") related to Integrys Business Support ("IBS") hardware and software and other non-labor expenses for the ICE Project. (AG Ex. 1.0, 32-35; AG Ex. 1.2, 9; AG Ex. 1.1, 7; AG Ex. 7.0, 20-23, AG Ex. 7.1, 7, AG Ex. 7.2, 8.) ICE is a consolidated IBS customer system, scheduled to go in service in 2015. (PGL Ex. 13.0, 9; NS Ex. 13.0, 9.) Mr. Effron's calculations use annualized 2014 expenses to adjust the 2015 test year. Ms. Hathhorn testified that it does not appear that annualizing the historical costs of this project is appropriate. Mr. Effron's analysis does not account for the fact that the Companies forecast the ICE system to be placed in service in 2015 and placing the asset into service will trigger the larger depreciation and ROA charges from IBS at that time. Mr. Effron also provided no evidence to the contrary that the majority of the non-labor expenses will begin in 2015 as the software goes in service. (Staff Ex. 6.0, 23; NS-PGL Ex. 27.0, 6-7.)

The AG also called into question whether or not the increased ICE costs would be incurred due to the announced acquisition of Integrys Energy Group, Inc. by Wisconsin Energy Corp. (AG Ex. 7.0, 22-23.) The AG opines that the ICE project would be a likely target for operational and financial benefits referenced in the announcement of the acquisition. Staff maintains that the rates in the instant proceeding must reflect only test year costs, and anticipated savings outside the test period are not allowed in rates at this time. (Staff Ex. 6.0, 24-25.) Staff discussed at the evidentiary hearing the Integrys Board of Directors' approval of the ICE document provided in discovery, confirming the 2015 in service date, and that savings are projected for 15 years. (Tr. 152:3-10[16]; 154:10-15, Sept. 23, 2014.) Therefore, based on the evidence, Staff recommends the Commission reject the AG adjustments for the ICE project.

b. Advertising Expenses

The Commission should adopt Staff's rebuttal adjustment to eliminate advertising expenses that are of a promotional, goodwill or institutional nature. Staff's adjustment includes promotional or goodwill natured costs for support of events; expenditures for employee apparel and event "premiums", e.g., pens, pencils, mini-flashlights and travel mugs; and expenditures to provide funding of events for charitable organizations. (Staff Ex. 2.0, 5-6; Staff Ex. 7.0, 3-5.)

The issue of advertising expenses that are of a promotional, goodwill or institutional nature are addressed in Section 9-225 of the Act which expressly states in part:

[16] At line 5, the word private should be project.

> In any general rate increase requested by any gas or electric utility company under the provisions of this Act, the Commission shall not consider, for the purpose of determining any rate, charge or classification of costs, any direct or indirect expenditures for promotional, political, institutional or goodwill advertising, unless the Commission finds the advertising to be in the best interest of the Consumer or authorized as provided pursuant to subsection 3 of this Section. 220 ILCS 5/9-225(2).

Section 9-225 of the Act defines goodwill or institutional advertising as:

> [A]ny advertising either on a local or national basis designed primarily to bring the utility's name before the general public in such a way as to improve the image of the utility or to promote controversial issues for the utility or the industry. 220 ILCS 5/9-225(1)(d).

The Commission adopted identical Staff adjustments to eliminate advertising expenses that were of a promotional, goodwill or institutional nature in the Companies' 2007, 2009 and 2011 rate cases. (Final Orders, Docket Nos. 07-0241/07-0242 (Cons.), February 5, 2008, p. 41; Docket Nos. 09-0166/09-0167 (Cons.), January 21, 2010, p. 81; and Docket Nos. 11-0280/11-0281 (Cons.), January 12, 2012, p. 47.) In the Companies' 2012 rate case, Staff made an identical proposal, but the Commission did not adopt a portion of Staff's proposed adjustment that the Commission determined to qualify as charitable contributions. (Final Order, Docket Nos. 12-0511/12-0512 (Cons.), June 18, 2013, p. 164.)

The Commission should not allow the Companies to include advertising that is of a charitable nature in rates in this proceeding. In the Companies' 2012 rate case, the Commission stated the Companies must be more careful in distinguishing sponsorship and institutional expenditures that are allowable for charitable purposes and those that are allowable advertising expenses. (Final Order, Docket Nos. 12-0511/12-0512 (Cons.), June 18, 2013, p. 164.) In spite of the Commission's direction, the Companies have continued to record expenditures that are of a promotional, goodwill or institutional nature that might be allowable for charitable purposes as advertising expenses. If the Companies request recovery of charitable costs as advertising expenditures under the guidelines provided by Section 9-225 of the Act, the Companies should not be permitted to reclassify expenditures during the proceeding to ask for recovery under Section 9-227 of the Act as Staff (and other parties) would not have the opportunity to adequately and timely review the expenditures for compliance with Section 9-227. The Commission should disallow for recovery through rates determined in these proceedings the sponsorship expenditures that have been recorded as advertising that do not meet the requirements under Section 9-225 of the Act. (Staff Ex. 2.0, 6-7; Staff Ex. 7.0, 5-7.)

Further, allowing the Companies to file a rate case with charitable costs for Staff to review as advertising expenses, and then allowing charitable costs to be included in rates as advertising, would give no meaning to the prohibition of promotional, goodwill, and/or institutional advertising required of the Commission by Section 9-225 of the Act.

c. Institutional Events

The Commission should not allow the Companies to recover, through rates set in this proceeding, miscellaneous general expenses for "institutional events annual fund-raising support" because the costs are either of a promotional, goodwill or institutional nature, not necessary to provide utility service to ratepayers, and are therefore barred for cost recovery under Section 9-225 of the Public Utilities Act. (Staff Ex. 2.0, 12; Staff Ex. 7.0, 7-8.)

Support of fund-raising events, while promoting good corporate citizenship, are of a promotional and goodwill nature which presents the Companies' names before the general public in a way as to improve their image. These expenditures are not necessary to provide utility service and provide no direct benefit to ratepayers. (Staff Ex. 2.0, 13; Staff Ex. 7.0, 9.)

The Act requires costs "designed primarily to bring the utility's name before the general public in such a way to improve the image of the utility or to promote controversial issues for the utility or the industry" to be excluded from rates. (220 ILCS 5/9-225(1)(d) and 9-225(2).)

In the Companies' most recent rate cases, (Docket Nos. 12-0511/12-0512 (Cons.)), Staff made an identical proposal which the Commission adopted, except for a portion that the Commission determined to qualify as charitable contributions. (Staff Ex. 2.0, 13.) In this proceeding, however, the Commission should adopt Staff's entire adjustment for the same reasons discussed above in section C.3.b for Advertising Expenses. Expenditures which are of a promotional, goodwill or institutional nature, which are recorded as miscellaneous general expenses, should not be considered for the purpose of determining rates pursuant to Section 9-225 of the Act. (Staff Ex. 2.0, 14; Staff Ex. 7.0, 9.)

Allowing the Companies to file a rate case with expenditures which are of a promotional, goodwill or institutional nature for Staff to review as institutional events, and then allowing promotional, goodwill or institutional costs to be included in rates as institutional events, would give no meaning to the prohibition of promotional, goodwill, and/or institutional advertising required of the Commission by Section 9-225 of the Act.

d. Charitable Contributions

The Commission should adopt Staff's rebuttal adjustment to reduce test year expenses for charitable contributions for which there is no tangible evidence of benefit to ratepayers in the Companies' service territory. Staff's adjustment eliminates contributions made to organizations outside the Companies' service territory and colleges and universities outside of the State. (Staff Ex. 2.0, 14-16; Staff Ex. 7.0, 10.)

In the Companies' most recent rate case, the Commission accepted the portion of Staff's proposed adjustments to disallow contributions made to organizations outside the Companies' service territory and to colleges and universities outside of the State of Illinois. (Final Order, Docket Nos. 12-0511/12-0512 (Cons.), June 18, 2013, pp. 166-167.)

e. Social and Service Club Membership Dues

The Commission should adopt Staff's rebuttal adjustments to remove social and service club membership dues which are promotional or goodwill in nature. While these social and service club membership dues may promote good corporate citizenship, they are not necessary in providing utility service. Ratepayers should not be burdened with the expense of the Companies participating in these organizations, and these nonessential expenses should be removed from the Companies' test year operating expenses. (Staff Ex. 2.0, 17-18; Staff Ex. 7.0, 11-12.)

In the Companies' 2007, 2009, 2011 and 2012 rate cases the Commission accepted Staff's proposed adjustments to remove certain social and service club membership dues. (Final Orders, Docket Nos. 07-0241/07-0242 (Cons.), February 5, 2008, pp. 41-42; Docket Nos. 09-0166/09-0167 (Cons.), January 21, 2010, p. 41; Docket Nos. 11-0280/11-0281 (Cons.), January 12, 2012, p. 46; and Docket Nos. 12-0511/12-0512 (Cons.), June 18, 2013, p. 119.)

4. Amortization Period for Rate Case Expenses

The Commission should take administrative notice of the Companies' filing in Docket No. 14-0496 (Wisconsin Energy Corporation, Integrys Energy Group, Inc., Peoples Energy, LLC, The Peoples Gas Light and Coke Company, North Shore Gas Company, ATC Management Inc., and American Transmission Company LLC, Application pursuant to Section 7-204 of the Public Utilities Act for authority to engage in a Reorganization, to enter into agreements with affiliated interests pursuant to Section 7-101, and for such other approvals as may be required under the Public Utilities Act to effectuate the Reorganization), and amortize rate case costs over a period of 2 and one-half years. (Staff Ex. 7.0, 14.) In their merger filing, the Companies committed that any further requests to change base rates would become effective no earlier than two years after the reorganization transaction closes and that the base rates resulting from the instant proceeding would remain "…unchanged for two and a half years or so after they are approved by the Commission." New rates in the instant proceeding would go into effect on or before February 1, 2015. (Docket No. 14-0496, Joint Applicants Ex. 1.0, 21.) The reorganization transaction will not close until July 2015 at the earliest. (Id., at 14.) A July 2015 closing means that the Companies' next base rates would go into effect no earlier than July 2017, that is, two and a half years from when a Commission order is issued in the instant proceeding. (Staff Ex. 7.0, 13-14.)

While the outcome of the merger case is unknown, Staff cannot recall a merger petition which was denied.[17] The Commission should consider the history of merger approvals and adopt two and one-half years as the minimum period for which base rates resulting from the instant proceeding will be in effect.

5. Peer Group Analyses

VI. RATE OF RETURN

A. Overview

Several witnesses submitted testimony regarding the Companies' costs of capital. On behalf of NS-PGL, Mr. Paul R. Moul presented testimony regarding the Companies' cost of common equity (NS-PGL Exs. 3.0, 19.0, and 35.0) and Ms. Lisa J. Gast presented testimony regarding the Companies' proposed capital structures and overall weighted average costs of capital ("WACC") (NS-PGL Exs. 2.0, 18.0, and 34.0). On behalf of the City of Chicago, Citizens Utility Board and IIEC, Mr. Michael P. Gorman presented testimony regarding the Companies' cost of common equity, capital structures, and WACCs. (City/CUB/IIEC Joint Exs. 1.0 and 2.0.) On behalf of Staff, Ms. Janis Freetly presented testimony regarding the Companies' cost of common equity, capital structures, and WACCs. (Staff Exs. 3.0 and 8.0.) The following tables present Staff's proposals for the Companies' capital structures and component costs:

[17] *See, e.g.* Docket Nos. 13-0618, 13-0595, 13-0362, 11-0559, 11-0046, 10-0588, 06-0540, all recently-approved Article 7 reorganizations..

North Shore Gas Company				
		Percent of		Weighted
	Amount	Total Capital	Cost	Cost
Long-term Debt	$79,784,000	38.94%	4.13%	1.61%
Short-term Debt	$21,678,000	10.58%	0.74%	0.08%
Common Equity	$103,435,000	50.48%	9.00%	4.54%
Total Capital	$204,897,000	100.00%		
Weighted Average Cost of Capital				**6.23%**

The Peoples Gas Light and Coke Company				
		Percent of		Weighted
	Amount	Total Capital	Cost	Cost
Long-term Debt	$864,589,000	46.51%	4.26%	1.98%
Short-term Debt	$58,805,000	3.16%	0.91%	0.03%
Common Equity	$935,610,000	50.33%	9.00%	4.53%
Total Capital	$1,859,004,000	100.00%		
Weighted Average Cost of Capital				**6.54%**

NS-PGL witness Gast presented revised capital structures for the Companies in her rebuttal testimony (NS-PGL 18.1P and 18.1N). Staff witness Freetly accepted the revised capital structures, which are presented in the tables above. While the Companies and Staff agree on the embedded cost of long-term debt for NS, the embedded cost of long-term debt for PGL, the costs of short-term debt and the cost of common equity for both Companies remain contested.

B. Capital Structure

The Companies propose using an average 2015 capital structure that contains 38.94% long-term debt, 10.58% short-term debt, and 50.48% common equity for North Shore and an average 2015 capital structure that contains 46.51% long-term debt, 3.16% short-term debt, and 50.33% common equity for Peoples Gas. (NS-PGL 18.1P and 18.1N.) Staff accepts the Companies' proposed capital structures. (Staff Ex. 8.0, 2.)

C. Cost of Short-Term Debt

According to Staff, the cost of short-term debt is 0.74% for North Shore and 0.91% for Peoples Gas. (Staff Ex. 8.0, 2-3, Sch. 8.01.) The interest rate on short-term debt for both North Shore and Peoples Gas is based on commercial paper rates at the time of borrowing. To estimate the Companies' cost of short-term debt, Staff started with the June 12, 2014, 0.24% annual yield on 30-day A2/P2 nonfinancial commercial paper. (Staff Ex. 3.0, 5.) Then, Staff added the annual percentage cost of bank commitment fees to the annual commercial paper yield. Staff divided the amount in fees by the updated average 2015 balance of short-term debt projected to be outstanding to derive the commitment fees in percentage terms. For North Shore, adding the resulting 50 basis points to the 0.24% commercial paper yield produces a cost of short-term debt of 0.74% (0.24% + 0.50% = 0.74%). (Staff Ex. 8.0, 2-3.) For Peoples Gas, adding the resulting 67 basis points to the 0.24% commercial paper yield produces a cost of short-term debt for Peoples Gas of 0.91% (0.24% + 0.67% = 0.91%). (Staff Ex. 8.0, 3.)

Argument

The Companies relied on *forecasted* commercial paper rates to estimate the cost of short-term debt for each of the Companies. However, the Companies' interest rate forecasts have not been accurate. For example, in its 2011 rate cases, the Companies forecasted that the 30-day A-2/P-2 commercial paper rate would average 1.95% in 2012. In contrast, the 30-day A-2/P-2 commercial paper rate averaged 0.46% that year, which changed little from the January 2011 rate of 0.38%. In its 2012 rate cases, the Companies forecasted that the 30-day A-2/P-2 commercial paper rate would average 0.79% in 2013. In contrast, the 30-day A-2/P-2 commercial paper rate averaged 0.30% that year, even lower than the March 2012 rate of 0.45%. (Staff Ex. 3.0, 4.) In summary, the Companies' proposal to base the cost of new short-term debt issues on interest rate forecasts should be rejected in favor of recent actual short-term interest rates because the latter have proven to be more accurate predictors of future interest rates than the former. (Staff Ex. 8.0, 3-4.)

D. Cost of Long-Term Debt

The Companies and Staff agree that 4.13% is a reasonable estimate of North Shore's embedded cost of long-term debt for average 2015. (Staff Ex. 3.0, 6; NS Ex. 2.0, 7.) The Companies and Staff do not agree on the embedded cost of long-term debt for Peoples Gas, due to the Companies' use of forecasted interest rates for the anticipated 2015 issuances.

For Peoples Gas, Staff and the Company agree on the interest rates for all long-term debt issues except those planned for 2015. (Staff Ex. 8.0, 7, Sch.8.02P.) However, Peoples Gas completed the pricing for the Series BBB bonds in August, with the actual interest rate set at 4.21%, after Staff filed its rebuttal testimony. (NS-PGL Ex. 34.0, 3.) Hence, the interest rate for the Series BBB on line 12 of Staff Schedule 8.02P should be changed from 4.66% to 4.21% to reflect the actual interest rate. This change reduces the embedded cost of long-term debt for Peoples Gas from 4.36% to 4.26%. (Attachment A)

The interest rates for the planned 2015 issuances should be based on recent actual interest rates. For the tax exempt Series WW planned to be issued in 2015, Ms. Freetly used the actual 3.90% interest rate that the Company recently obtained on the similar tax exempt Series VV.[18] (Staff Ex. 8.0, p. 7, Sch. 8.02P, line 13.) For the non-tax exempt Series CCC planned issuance for 2015, Ms. Freetly used the current yield on 30-year A-rated corporate bonds of 4.66%.[19] (Staff Ex. 3.0, 7; Staff Ex. 8.0, 7; Sch. 8.02P, line 14.)

Argument

Forecasted interest rates should not be used for estimating the cost of the planned 2015 issuances of long-term debt for Peoples Gas as Ms. Gast insists. Academic research has shown that forecasters' predictions of future movements of interest rates are inaccurate. Indeed, one financial text states, "forecasting interest rates is a perilous business. To their embarrassment, even the top experts are frequently wrong in their forecasts."[20] Forecasts are frequently wrong even in the direction, let alone the magnitude and timing, of future interest rate changes. For example, the November 1, 2013 Blue Chip forecasts that Company witness Moul relied on (NS and PGL Ex. 3.12, 2) is already proving to be inaccurate. Blue Chip forecasted increasing yields from the fourth quarter 2013 through the second quarter of 2014.

[18] The two debt issues differ slightly in term to maturity, which is 16 years for Series VV and 18 years for Series WW.

[19] The 4.66% yield was as of June 11, 2014, the most current yield available when Staff was preparing direct testimony, Given that both the 30-year Series BBB bonds were issued with a 4.21% interest rate, it would follow that same interest rate would be the best available estimate for the interest rate on the 30-year Series CCC bonds planned for issuance in 2015. However, since Staff did not state in testimony that the interest rate on the Series CCC bonds should be updated to equal that on the Series BBB bonds, Staff has kept the Series CCC interest rate at 4.66% in Attachment A.

[20] Frederic S. Mishkin, The Economics of Money, Banking, and Financial Markets, Forth Edition, 1995, p. 134.

However, the actual yields have fallen over that time period.[21] Table 1 demonstrates that the Blue Chip forecasts Mr. Moul relied on overstated the yields on both Treasury and Corporate bonds for the first and second quarter of 2014.

Table 1							
	10-Year T-bonds				30-Year T-bonds		
	Forecasted Rate	Actual Rate	Forecast Error		Forecasted Rate	Actual Rate	Forecast Error
4Q 2013	2.70%	2.75%	0.05%		3.70%	3.79%	0.09%
1Q 2014	2.80%	2.76%	-0.04%		3.80%	3.68%	-0.12%
2Q 2014	2.90%	2.62%	-0.28%		3.90%	3.44%	-0.46%
	Aaa corporate bonds				Baa corporate bonds		
	Forecasted Rate	Actual Rate	Forecast Error		Forecasted Rate	Actual Rate	Forecast Error
4Q 2013	4.50%	4.59%	0.09%		5.40%	5.36%	-0.04%
1Q 2014	4.60%	4.44%	-0.16%		5.50%	5.12%	-0.38%
2Q 2014	4.70%	4.22%	-0.48%		5.60%	4.82%	-0.78%

Further evidence of problems with attempting to predict interest rates is the difference in the forecasts provided by the many sources available. If forecasting could be done with a reasonable degree of accuracy, there should be little divergence among the various sources. That is not the case. This is illustrated by the various forecasted rates for the 10-year Treasury note in Table 2 below.

Table 2			
Source	Date of Forecast	Forecast Period	Forecasted Rate
Forecasts.org	8/21/2014	4th Quarter 2014	2.28%
FreddieMac	8/12/2014	4th Quarter 2014	2.60%
EconomicOutlookgroup.com	8/21/2014	4th Quarter 2014	3.50%
Survey of Professional Forecaster	8/15/2014	4th Quarter 2014	2.80%

[21] The Actual Rate is the quarterly average rate derived from monthly yields at www.federalreserve.gov.

As the table above shows, the selected forecasts for the fourth quarter of 2014 range from 2.28% to 3.50%.[22] That a 1.22 percentage point spread exists among even a small sampling of forecasts just a few months before the forecast period demonstrates the difficulty in accurately predicting future movements of interest rates. Moreover, the differences among forecasts lead to the further problem of selecting a forecast, since it is unknown which of these disparate results will ultimately be the closest to realized rates. (Staff Ex. 8.0, 4-6.)

Contrary to the Companies' argument, using current interest rates, as Staff proposes, does not assume that the current interest rates will continue to be available through the 2015 test year. Staff is not suggesting that interest rates will not change; in fact, Staff very much expects interest rates to change. Unfortunately, no one can accurately predict the direction, magnitude, or timing of future interest rate changes. Rather, Staff's argument is that current interest rates have proven to be superior predictors of future interest rates than professional forecasters. As shown in the table below, the forecasted rates that Peoples Gas proposed for the two debt Series issued in 2014 have a higher forecast error that Staff's proposed current rates. (Staff Ex. 8.0, 3.)

[22] The four sources cited represent the most easily obtainable sources Staff was able to access in the limited time available. There are likely numerous other sources for such forecasts. Thus, the range of potential forecasts from <u>all</u> available sources would likely be even larger.

		Proposed	Actual	Forecast
Bonds	Party	Rate	Rate	Error
Series VV	Company Direct	5.05%	3.90%	1.15%
	Staff Direct	3.49%		-0.41%
Series BBB	Company Direct	5.50%	4.21%	1.29%
	Company Rebuttal	4.70%		0.49%
	Staff Direct	4.66%		0.45%

Because current interest rates have proven to be more accurate predictors of future interest rates than interest rate forecasts, the Commission should continue to use actual spot (current) interest rates to estimate the Companies' cost of debt.

E. Cost of Common Equity

1. Staff's Analysis

Staff witness Janis Freetly's estimate of the investor-required rate of return on common equity for Peoples Gas and North Shore is 9.00%. (Staff Ex. 8.0, Sch. 8.01.) Ms. Freetly began her analysis with the data that the Companies' witness Mr. Moul used in his DCF and CAPM analyses while correcting the most significant flaws in those analyses. She applied both models to Mr. Moul's sample, the "Delivery Group." (Staff Ex. 3.0, 8.)

a. DCF Analysis

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend prices that stock prices embody. The companies in the Delivery Group pay dividends quarterly. Therefore, Ms. Freetly applied a quarterly DCF model. (Staff Ex. 3.0, 8-9.)

In order to reduce issues in this proceeding, Ms. Freetly revised her DCF analysis in rebuttal testimony. (Staff Ex. 8.0, 11-13.) While Staff does not agree with Mr. Moul's position that stock prices measured over a longer time period are superior for measuring the investor-required rate of return on common equity, Ms. Freetly adopted Mr. Moul's 6-month average dividend yield of 3.89%. In addition, Ms. Freetly agreed to exclude the Value Line projected growth rates for book value per share, cash flow per share and percent retained to common equity from the growth rate used in her DCF analysis; although, Mr. Moul had testified in his direct testimony that he considered those growth rates in his own analysis before he disowned them in his rebuttal testimony. (NS Ex. 3.0, 18; NS-PGL Ex. 19.0, 8-10.)

However, despite Mr. Moul's protestations to the contrary (NS-PGL Ex. 19.0, 10-11.), the Value Line projected growth in dividends per share ("dps") should not be ignored. As Mr. Moul indicated, the Delivery Group average Value Line projected growth rate of earnings per share ("eps") is higher than the Delivery Group average Value Line projected growth rate of dps. However, as Mr. Moul testified, DCF theory holds that dividend growth will equal earnings growth when the payout ratio is constant. (NS-PGL Ex. 19.0, 8.) He then indicates that Value Line projects declining dividend payout ratios for the Delivery Group. (Id., 10) This explains why Value Line's forecasted eps growth rate exceeds its forecasted dps growth rate. ***If*** the lower payout ratio persists, long-term dividend growth will eventually converge to the level of earnings growth. This is because growth is directly related to the earnings retention ratio:

Growth = Rate of Return on New Investment x Earnings Retention Rate

Nonetheless, this higher long term earnings growth cannot be achieved without slowing near term dividend growth. Because the DCF is a *dividend* discount model rather than an earnings discount model, ignoring the slowing in the growth of dividends that is necessary to increase the earnings retention rate, leads to an upwardly biased estimate of the investor-required rate of return on common equity.

Significantly, Mr. Moul did not contest the economic rationale for including dps growth in DCF analysis described in the preceding paragraph. Rather, he alleged that Ms. Freetly's proposal to include growth in dividends per share in the DCF growth rate is a first for Staff and is therefore a departure from Staff precedent in past rate cases. (NS-PGL Ex. 35.0, 5.) However, Staff has used growth in dividends per share in the DCF model when available from Staff's growth rate sources. For example, in Docket No. 90-0169, Staff used the five-year projected growth rate in dividends from those sources that provided them (i.e., Goldman Sachs, Prudential-Bache, Merrill Lynch and Value Line). (Order, Docket No. 90-0169, March 8, 1991, 97) Currently, Staff usually relies on growth rates from Zacks and Reuters for the DCF model, which do not provide projected growth in dividends per share; they only publish growth in earnings per share.

Using the data presented by Mr. Moul on NS and PGL Ex. 3.8, Ms. Freetly first calculated the average Value Line growth projection by averaging the growth in eps and dps. She then computed the average of the growth rates from I/B/E/S First Call, Zacks, Morningstar and the average Value Line growth projection. The resulting growth rate estimate is 4.82%. Hence, Staff's 8.71% DCF cost of common equity estimate was derived by adding the 4.82% growth rate to Mr. Moul's 3.89% dividend yield.

b. CAPM Analysis

According to financial theory, the required rate of return on a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-adverse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Ms. Freetly used a one-factor risk premium model, the Capital Asset Pricing model, to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which cannot be eliminated through portfolio diversification. (Staff Ex. 3.0, 11-13.)

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Ms. Freetly supplemented Mr. Moul's Value Line betas with the Zacks betas and betas calculated using a regression analysis that the Commission has routinely adopted for the CAPM. The Delivery Group's average Value Line, Zacks, and regression beta estimates were 0.69, 0.60, and 0.59, respectively. The Value Line regression employs 259 weekly observations of stock return data regressed against the returns of the New York Stock Exchange ("NYSE") Composite Index. Both the regression beta and Zacks betas employ sixty monthly observations; however, while Zacks betas regress stock returns against the S&P 500 Index, the regression beta regresses stock returns against the NYSE Index. Since the Zacks beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as Value Line uses), Ms. Freetly averaged the Zacks and regression results to avoid over-weighting betas calculated from monthly returns. She then averaged that result with the Value Line beta, which produced a beta for the Delivery Group of 0.64. (Staff Ex. 3.0, 17-21.)

For the risk-free rate parameter, Ms. Freetly used the October 31, 2013 3.66% yield on thirty-year U.S. Treasury bonds. (Staff Ex. 3.0, 15-17.)

Finally, for the expected rate of return on the market parameter, Ms. Freetly conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market equals 12.43%. (Staff Ex. 3.0, 17.) Inputting those three parameters into the CAPM, Staff's CAPM estimate of the cost of common equity for the Delivery Group is 9.27%. (Staff Ex. 3.0, 21; Sch. 3.06.)

Argument

The Companies insist that the estimation of the risk-free rate should be based on *forecasts* rather than spot yields. (NS-PGL Ex. 19.0, 11-12.) However, interest rates are constantly adjusting, and accurately forecasting the movements of interest rates is problematic, as discussed previously. In contrast, current U.S. Treasury yields, which Staff used to estimate the risk-free rate, are set directly by investors and reflect all relevant, available information, including investor expectations regarding future interest rates. Consequently, investor appraisals of the value of forecasts are also reflected in current interest rates. Therefore, if investors believe that the Blue Chip Financial Forecasts ("BCFF") forecasts are valuable, that belief would be reflected in the current market interest rates. Likewise, if investors believe that the BCFF forecasts are not valuable, the belief would be reflected in the current market interest rates. In summary, if one uses current market interest rates in a risk premium analysis, speculation of whether investor expectations of future interest rates equals those from a particular forecast reporting service, such as BCFF, is unnecessary. Thus, the Commission should continue to rely on current, observable market interest rates rather than the projected rates that Ms. Moul used in his analysis. (Staff Ex. 8.0, 13-14.)

Mr. Moul recommends the sole use of Value Line betas in the CAPM analysis. He criticizes Ms. Freetly's use of the regression betas and adjusted Zacks betas in her CAPM analysis because they could not have been relied on by investors. (NS-PGL Ex. 19.0, 13.) If Mr. Moul's argument that publication was a necessary and sufficient condition for the validity of a beta estimate, and it is not, then it would follow that Zacks' published beta estimates are as valid as Value Line's. In this case, the gas sample beta would equal 0.55 (The Value Line beta for the Delivery Group is 0.69 while the unadjusted published Zacks beta for the Delivery Group is 0.40. The average is 0.55 = [(0.69 + 0.40)/2]). However, publication is neither a necessary nor sufficient condition for establishing the validity of a beta estimate because it merely serves as a proxy for the unobservable true beta, which measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. (Staff Ex. 3.0, 18-21.) Consequently, which beta estimates are more accurate is unknown. Thus, the Value Line methodology is not inherently superior to Staff's methodology. In fact, different beta estimation methologies can produce different betas when those methologies employ different samples of stock return data. Thus, just as Mr. Moul and Ms. Freetly used multiple estimates of long-term growth in their DCF analyses, Ms. Freetly used multiple approaches to estimate beta for her risk premium analysis.

The validity of a beta estimation methodology is not a function of whether investors rely upon its beta estimates. Rather, the validity of the methodology is a function of its ability to explain stock price behavior. The methodology Staff used to calculate the regression beta for the Delivery Group, which Staff has regularly used and the Commission has consistently approved,[23] employs the same monthly frequency of stock price data as the widely accepted Merrill Lynch methodology. Further, Mr. Moul's argument to exclude Staff calculated betas and rely upon only Value Line betas was rejected multiple times by the Commission, including the Companies' 2009 rate case. In that proceeding, the Commission adopted Staff's multiple-source approach to estimating beta, stating:

> We agree that, in the same way we rely on multiple models to determine the cost of equity, Staff's well-considered use of multiple beta sources is beneficial to reduce measurement error from any individual estimate. Moreover, we find that Staff's beta estimate appropriately weights the beta estimates from those three sources. Thus, we adopt Staff's beta estimate of 0.59. (Order, Docket Nos. 09-0166/09-0167 (Cons.), January 21, 2010, 126-127.)

The beta estimate Staff used in its CAPM analysis in this proceeding was calculated in the same manner as the beta adopted in that proceeding. (Staff Ex. 8.0, 14-15.)

c. Recommendation

Based on a simple average of the mean sample estimates from her revised DCF and risk premium models, Ms. Freetly estimated that the cost of common equity for the Delivery Group is 9.00%.

Argument

[23] Order, Docket No. 02-0837, October 17, 2003, 37-38; Order, Docket Nos. 02-0798/03-0008/03-0009 (Cons.), October 22, 2003, 85; Order, Docket No. 00-0340, February 15, 2001, 25; Order, Docket No. 03-0403, April 13, 2004, 42; and Order, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), November 21, 2006, 145.

Mr. Moul argues that Staff's cost of common equity recommendation is "simply not representative of the returns investors can earn on other investments of comparable risk." (NS-PGL Ex. 19.0, 2.) His conclusion rests largely on a comparison to previously authorized returns for other companies, in other jurisdictions, at other times representing other market environments. Mr. Moul's review of other authorized returns fails to specify crucial factors that influenced the allowed returns in those proceedings. For instance, Mr. Moul does not identify the relative risk, as exemplified by credit rating or any other metric, of each of the utilities involved in those return decisions. Nor does he identify the amount of common stock flotation cost adjustment, if any, was included in each of those decisions. He also fails to provide any context regarding the regulatory framework and market environment in which those decisions were made. Without such data, any evaluation of the return recommendations in this proceeding via comparison to the returns authorized for other natural gas utilities is useless because there is no basis on which to assess comparability. In addition, it also introduces a circularity problem, since it would establish an authorized rate of return on the basis of other authorized rates of return. (Staff Ex. 8.0, 8.)

Mr. Moul further argues that Value Line projects higher returns for the companies in the Delivery Group than your analysis indicates. (NS-PGL Ex. 18.0, 4-5.) His approach, however, is fatally flawed because it relies on projected returns on book equity, which erroneously implies that accounting returns on book equity are acceptable substitutes for investor-required returns. Investor-required returns are only loosely related to accounting returns; they are certainly not interchangeable. For example, the return on book value of common equity is entirely unaffected by changes in the investor-required rate of return. That is, due to a decline in risk, risk premiums, or the time value of money, investors would bid up the price of a stock, thereby reducing the implied required rate of return, but the anticipated book equity would not change. Therefore, projected returns on book equity cannot be substituted for investor-required returns. In addition, earned returns include the effect of any unregulated operations of those companies, which further reduces their usefulness as gauges of the investor-required returns on lower risk utility operations. (Staff Ex. 8.0, 8-9.)

Ms. Freetly presented support for her 9.0% cost of common equity recommendation being representative of the return investors can earn on other investments of comparable risk. Duff & Phelps regularly reviews fluctuations in global economic and financial conditions to develop equity risk premium ("ERP") recommendations.[24] According to Duff & Phelps, the U.S. equity risk premium is 5.0%. Duff & Phelps developed its current ERP recommendation in conjunction with a "normalized" 20-year yield on U.S. government bonds of 4.0% as the risk-free rate, implying a 9.0% "base" U.S. cost of equity capital estimate at the end of February 2013.

American Appraisal publishes the Equity Risk Premium Quarterly.[25] In its July 2014 report, the U.S. ERP (i.e., the ERP for the market as a whole) for the second quarter of 2014 was determined to be 6.0% combined with the actual risk-free rate as of April 2014, which is consistent with their conclusion for the first quarter of 2014. The yield on 30-year U.S. Treasury bonds was 3.52% in April 2014. Hence, according to American Appraisal, the implied U.S. cost of equity capital is 9.52% (6.0% + 3.52%).

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[24] Duff & Phelps, *Client Alert – Duff & Phelps Decreases U.S. Equity Risk Premium Recommendation to 5.0%*, Effective February 28, 2013, March 20, 2013.

[25] American Appraisal, Equity Risk Premium Quarterly, July 2014

Aswath Damodaran, Professor of Finance at the Stern School of Business at New York University, developed a forward-looking approach to calculating an expected ERP based on current market data. Id. He estimated that the implied ERP equaled 5.38% at the end of June 2014. Adding the 5.38% ERP to the yield on 30-year Treasury bonds in June 2014 of 3.42%, results in an implied cost of equity capital of 8.80% for the market as a whole.

Hence, these cost of equity estimates for the market as a whole, which is riskier than gas distribution utilities, indicate that Staff's 9.0% cost of equity recommendation is not too low and further demonstrates that Mr. Moul's 10.25% cost of equity estimate is far too high. (Staff Ex. 8.0, 9-10.)

2. Companies' Analysis

Company witness Moul relied on three models to measure the cost of common equity for the Companies: DCF, risk premium, and CAPM. He applied those models using average data for his Delivery Group and derived the following estimates:

Model	**Sample Estimate**
DCF	9.71%
RP	11.50%
CAPM	9.62%
Average	10.28%

From this average, Mr. Moul opined that a 10.25% return on equity was reasonable for this case. Mr. Moul also conducted a Comparable Earnings analysis, which indicated a 10.30% cost of common equity, which he claims confirms the reasonableness of his recommendation. (NS Ex. 3.0, 6 and NS Ex. 3.2.)

Mr. Moul's analysis contains several flaws that lead him to over-estimate the Companies' cost of common equity. The most significant flaws in his analysis are: (1) inclusion of the results of an inappropriate risk premium model; (2) use of an inappropriately high growth rate in his DCF analysis; and (3) inclusion of an unwarranted leverage adjustment in his DCF and CAPM estimates. (Staff Ex. 3.0, 27-33; Staff Ex. 8.0, 15-20.)

a. Risk Premium Analysis

Mr. Moul began with a projected yield of 5.25% on A-rated public utility bonds, based on 4.25% Blue Chip forecasts of 30-year Treasury rates plus a yield spread of 1.00% on A-rated public utility bonds and long-term Treasury bonds derived from historical data. Next, he developed an equity risk premium of 6.25%, which represents the historical spread between the returns on large common stocks and the yields on long-term government bonds. He then added the 6.25% equity risk premium to the 5.25% A-rated bond yield, which results in his 11.50% estimate of cost of common equity. (NS Ex. 3.0, 26-28.)

Even a quick glance would detect that the return on equity estimate from Mr. Moul's risk premium analysis is not like the others. There could be many contributors to this outlier status but there is one obvious one: Mr. Moul used the returns for the S&P500, which largely composes non-rate regulated industrial companies. (NS Ex. 3.0, 28.)[26] Because the S&P500 is riskier than utilities generally, its investor required rate of return exceeds the cost of common equity for gas utilities.

[26] Mr. Moul relied on "large company stock returns" from the 2013 Classic Yearbook for Stocks, Bonds, Bills and Inflation published by Morningstar to develop his equity risk premium (continued…)

Mr. Moul's equity risk premium estimate is derived from historical data, which is inappropriate. Although his risk premium is intended to estimate an *investor-required return* for the Companies, it is based on the average spread between *earned returns* and interest rates. However, investor-required returns and earned returns are not the same. There is no means to ascertain whether the earned rates of return were above, equal or below the rate of return investors required. (Staff Ex. 3.0, 28.) Further, use of non-current data wrongly implies that market risk premiums revert to a mean that is observable, despite the fact that security returns approximate a random walk. Id.

Significantly, Mr. Moul did not defend his choice of the S&P500 as his proxy for PGL and NS. Rather, Mr. Moul defended his risk premium model by stating that his use of a very broad range of earned returns that were experienced historically should allay any concerns that earned returns obtained from historical data would not represent investor return requirements for the future. (NS-PGL Ex. 19.0, 14.) Contrary to his argument, the past pattern of earned returns is not useful in predicting future returns because the true mean of the market risk premium, if it exists, is not observable. Because the true mean cannot be observed, the selection of a measurement period will necessarily be arbitrary and will dictate the magnitude of the resulting risk premium, as Mr. Moul's testimony indicates. For example, had Mr. Moul used the 1966-2012 measurement period, his average equity risk premium estimate would have been 2.31% instead of 5.41%. This illustrates that his approach is unquestionably, and incurably,

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estimate. The "large company stock returns" were taken from the S&P500, which largely composes non-rate regulated industrial companies. (NS Ex. 3.0, 28) subject to manipulation and would only produce the "correct" risk premium by sheer chance, at best. (Staff Ex. 8.0, 16.)

In addition, rather than utilizing the current A-rated utility yield of 4.54%[27] as the base yield to which his risk premium is added, he relied on a 5.25% forecast of A-rated utility bond yields. This substitution inappropriately inflates his RP results by 0.71%. To begin with, the use of forecasted interest rates is unnecessary because current interest rates already reflect investors' current expectations for the future. Thus, there is no need to employ forecasts. Moreover, as difficult as it is to estimate investors' *current* required rates of return on common equity, the employment of forecasted interest rates essentially attempts to predict investors' *future* required rates of return, which compounds the difficulty.

b. Growth Rate in DCF Analysis

Mr. Moul used a growth rate of 5.25% in his DCF analysis, based on a range of growth rates of 4.70% to 5.58%. (NS and PGL Ex. 3.8) Although he considered the five-year projected growth rates for the Delivery Group from various sources (NS Ex. 3.0, 16-20), he ultimately relied on only two of the growth rate estimates. Further, he only included the estimates of growth in earnings per share while ignoring the growth in dividends per share. (Staff Ex. 3.0, 29-30.) If Mr. Moul would have taken a simple average of the projected growth in eps from I/B/E/S First Call, Zacks, Morningstar and Value Line, his growth rate estimate would have been 5.06% rather than 5.58%. Further, as discussed earlier, the Value Line dps projected growth rate must also be

[27] The Value Line Investment Survey, *Selection & Opinion*, February 7, 2014, p. 505. A-rated bond yield is for 10-30-13.

considered, which results in the 4.82% growth rate that Ms. Freetly used in the revised DCF presented in Staff Rebuttal. (Staff Ex. 8.0, 13.) When added to Mr. Moul's 4.00% dividend yield for the Delivery Group, his DCF estimate drops to 8.82%.

c. Leverage Adjustment

Mr. Moul argues that in order to apply a measurement of a return measured based on a firm's market-value capitalization compared to a book-value capitalization, the measurement must be adjusted before it is applied to the firm's capitalization measured based on book value. (NS-PGL Ex. 19.0, 17.) His argument is effectively an espousal of fair-value rate making, which entails estimating the fair, or market, value of a utility's property and then applying a market ROE to that value. (See., e.g., *Union Electric Co. v. Illinois Commerce Comm'n*, 77 Ill.2d 364, 374-375 (1979)) Section 9-210 of the Act put an end to fair-value ratemaking[28] ("For purposes of establishing the value of public utility property, when determining rates or charges, or for any other reason, the Commission may base its determination on the original cost of such property.") (220 ILCS 5/9-210)) Mr. Moul's "leverage" adjustment would reverse that practice. The problem is that market to book ratio based adjustments to ROE would have the Commission fruitlessly "chase" market value. That would occur because market value is an inverse function of required rate of return and a direct function of expected cash flow. For example, if investors reduce their required rate of return, the market value will increase. If the Commission increases its authorized rate of return in reaction to that increase in market value, the utility's cash flow will increase, which in turn will lead to an even higher utility market value, which by Mr. Moul's reasoning would, necessitate an

[28] Section 9-210 became effective January 1, 1986.

even greater upward adjustment to the authorized rate of return. These reactions -- investors reacting to the increased authorized ROR by raising market value and the Commission reacting to the increase in market value by raising the authorized ROR -- are mutually reinforcing, resulting in never ending upward spiral in both. (Staff Ex. 8.0, 17-20.)

Another problem with the leverage adjustment is that it would boost authorized rates of return in response to successful diversification into non-utility businesses. Ms. Freetly used a hypothetical example to illustrate this phenomenon: a company that includes two business segments of equal book value and equal risk – a regulated gas delivery company that is expected to earn exactly the investor-required return and an unregulated segment that is expected to earn more than the investor-required return. Investors (i.e., the market) would value the gas delivery segment equal to its book value because, at that price, investors would expect to earn exactly the return they require. However, investors would be willing to pay more than book value for the unregulated segment because of its higher-than-required earnings. Thus, the market value of the company as a whole would be bid up beyond its book value until the expected return equals the required return. Mr. Moul's argument suggests that the authorized return on rate base for the regulated gas delivery segment should be increased beyond the required return due to the excess expected earnings of the unregulated segment, which would, in turn, create excess earnings in the regulated gas delivery segment, pushing the market value higher still in a never-ending upward spiral. (Staff Ex. 8.0, 18.)

Mr. Moul erroneously argues that if the results of the DCF, which are based on the market price of the companies analyzed, are used to compute the weighted average cost of capital based on a book value capital structure used for ratesetting purposes, the utility will not recover its risk-adjusted capital cost because market value capital structures generally reflect less risk than book value capital structures. His argument suggests that when a company's market value exceeds its book value, the risk of a company increases if the capital structure is measured with book values of capital rather than market values of capital. Such a notion is without merit. The intrinsic risk level of a given company does not change simply because the manner in which it is measured has changed. Such an assertion is akin to claiming that the ambient temperature changes when the measurement scale is switched from Fahrenheit to Celsius. Mr. Moul has confused the measurement tool with the object to be measured. Specifically, capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. Financial risk arises from fixed, contractually required debt service payments; changing capital structure ratios from a market value basis to a book value basis does not affect a company's debt service requirements; thus, it does not change the company's risk.

As noted in a corporate finance textbook by Brealey, Myers and Allen, there are a variety of ways to define leverage and there is no law stating how it should be defined.[29] In any case, it is not appropriate to compare book value capital structures with market value capital structures any more than it would be appropriate to compare alternative measures of financial risk. Consequently, when assessing the relative financial risk of Peoples Gas and North Shore to the Delivery Group, Ms. Freetly

[29] Brealey, Myers and Allen, *Principles of Corporate Finance*, Ninth edition, McGraw-Hill/Irwin, p. 794.

compared the Companies' FFO interest coverage ratio to the Delivery Groups' FFO interest coverage. She did not compare the Companies' FFO interest coverage ratio to the Delivery Group's RCF to total debt ratio.

Further, the Staff's ratio analysis indicates that both North Shore and Peoples Gas have less financial risk than the Delivery Group. Ms. Freetly compared the values for the four ratios that Moody's Investors Service focuses on to assess the financial strength of gas and electric utilities: (1) funds from operations ("FFO") to interest coverage; (2) FFO to total debt; (3) retained cash flow ("RCF") to total debt coverage; and (4) debt to capitalization.[30] Each ratio was calculated as a 3-year average from 2010 through 2012. As can be seen by the Moody's Financial Guideline ratios at the top of Table 2, the higher the ratio for the FFO to interest coverage (FFO to total debt), and RCF to total debt coverage, the lower the financial risk. In contrast, the higher the debt to capitalization ratio, the higher the financial risk. As shown in Table 2, these ratio comparisons indicate that North Shore and Peoples Gas have less financial risk than the Delivery Group. (Staff Ex. 3.0, 23-25.) Hence, an upward adjustment to the cost of common equity for the Delivery Group is unwarranted. (Staff Ex. 3.0, 30-32.)

Table 2 –Ratio Analysis

	Aaa	Aa	A	Baa	Ba
Moody's Financial Guideline Ratios					
FFO/IC	> 8.0x	6.0-8.0x	4.5-6.0x	2.7-4.5x	1.5-2.7x
FFO/Debt	> 40%	30-40%	22-30%	13-22%	5-13%
RCF/Debt	> 35%	25-35%	17-25%	9-17%	0-9%
Debt/Capitalization	< 25%	25-35%	35-45%	45-55%	55-65%
Delivery Group					

[30] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, December 23, 2013.

	Aaa	Aa	A	Baa	Ba
FFOIC		6.1x			
FFO/Debt			24.7%		
RCF/Debt			18.4%		
Debt/Capitalization				51.6%	
North Shore Gas					
FFOIC		6.8x			
FFO/Debt			28.7%		
RCF/Debt			18.1%		
Debt/Capitalization			36.1%		
Peoples Gas					
FFOIC	9.0x				
FFO/Debt		34.0%			
RCF/Debt		25.6%			
Debt/Capitalization				47.0%	

Mr. Moul also argued that the Value Line betas cannot be used directly in the CAPM because they are derived based on market value. Hence, he unlevered and relevered the Value Line beta estimates for each of the companies in the Delivery Group for the book value common equity ratios using the Hamada formula. (NS Ex. 3.0, 29.) His leverage adjustment is simply wrong because it relies on a comparison of two different measures of financial leverage: book value capital structures and market value capital structures. (Staff Ex. 3.0, 32.)

Contrary to Mr. Moul's assertion, it is appropriate for the Commission to apply a market value derived cost of equity to the book value of common equity, even if the Companies' market value differs from its book value. Book value represents the funds a company receives from investors through security issuances on the primary market (i.e., transactions directly between a company and its investors) and reinvestment of earnings. Book value does not adjust to reflect changing investor assessments of the level or riskiness of future cash flow; it only measures how much money the company has invested in assets that serve its customers.

In contrast, the market value is the price investors are willing to pay each other for a security on the secondary market. That is, market value is set by transactions between investors rather than transactions between the company and its investors; therefore the market value of a company's securities has no direct bearing on the amount of funding the company has to invest in assets. Cost of common equity analysis uses market value data because market data continuously adjusts to reflect investor return requirements as they are continuously re-evaluated.

The market value of a stock would grow to exceed its book value only if investors expected to earn a return above their required return.[31] If that is the case, the market value will adjust upward until the expected return once again matches the required return. Thus, the market value always reflects the investor-required return, regardless of the book value. That is why it is appropriate, indeed necessary, to use a market-based cost of common equity for regulatory rate setting. Similarly, book value always represents the funds available to the company to invest in assets serving its customers, regardless of the market value. That is why it is appropriate and necessary to use a book value rate base for regulatory rate setting. The application of the market required return to the book value rate base simply takes the return investors demand to earn from a dollar invested in the common equity of a company, given the amount of risk in the common equity of the company and the current price of risk, and applies it to the number of common equity dollars invested in the rate base of the Companies. (Staff Ex. 8.0, 18-19.)

[31] Obviously, neither an expectation of higher than required earnings nor a reduction to the investor-required rate of return justifies a higher authorized rate of return.

Taken together, eliminating the inappropriate leverage adjustments to his DCF and CAPM estimates would produce a cost of common equity of 9.22% [(9.25% + 9.19%)/2]. Incorporating a more appropriate growth rate estimate in Mr. Moul's DCF analysis produces a cost of common equity of 9.00% [(8.82% + 9.19%)/2]. These corrected costs of equity estimates are significantly lower than the 10.25% he recommends for both Companies and is consistent with Staff's recommendation.

The Commission has properly rejected the use of leverage adjustments in several prior proceedings. (Order, Docket Nos. 01-0528/01-0628/01-0629 (Cons.), March 28, 2002, pp. 12-13; Order, Docket Nos. 99-0120/99-0134 (Cons.), August 25, 1999, p. 54; Order, Docket No. 94-0065, January 9, 1995, pp. 92-93.) In fact, Mr. Moul presented, and the Commission rejected, the exact same leverage adjustment, based on the same arguments, in the Companies' 2007 and 2009 rate cases. (Order, Docket Nos. 07-0241/07-0242 (Cons.), February 5, 2008, pp. 95-96; Order, Docket Nos. 09-0166/09-0167 (Cons.), January 21, 2010, pp. 128-129.) The Order from the 2007 rate case quite clearly sets forth, in great detail, the reasons such a leverage adjustment should be rejected once again in this proceeding.

> In the Commission's judgment, the book value capital structure reflects the amount of capital a utility actually utilizes to finance the acquisition of assets, including those assets used to provide utility service. In establishing the overall or weighted average cost of capital, the proportion of common equity, based on the book value capital structure, is multiplied by market-required return on common equity. The Commission has used this approach in establishing utility rates for at least twenty-five years. (E.g., <u>Ameren Order,</u> Docket Nos. 06-0070/06-0071/06-0072 (consol.) at 141) ("[t]he Commission observes that it has repeatedly rejected arguments in favor of using market-to-book ratios as the basis for establishing cost of common equity"). <u>Market value is not utilized in this calculation because it typically includes</u>

> appreciated value (as reflected in its stock price) above the Utilities' actual capital investments….
>
> Further, the Utilities have failed to establish why a mismatch between the financial risk reflected in the book value and market value capital structures is problematic. If the Utilities were correct that regulatory commissions, including this one, have been understating the market-required return on equity for twenty-five years, then the market values of common equity for utilities would not have remained well above the book values during that time. A practice of routinely understating the market-required return on common equity would have surely driven down the market values of common equity to near book value, but that has not happened. Accordingly, the Commission does not agree that an adjustment to the market required return on common equity is necessary to reflect the difference in financial risk between book value and market value capital structures. Therefore, we reject the Utilities' financial leverage adjustment to their DCF results and their proposal to impose a similar leveraging adjustment to the betas used in their CAPM analysis. Order, Docket Nos. 04-0241/0242, February 5, 2008, 95-96. (emphasis added)

F. Weighted Average Cost of Capital

Staff's overall cost of capital recommendation, incorporating Ms. Freetly's recommended capital structure and costs of short-term debt, long-term debt, and common equity, equals 6.23% for North Shore and 6.54% for Peoples Gas. The record consistently demonstrates that Ms. Freetly's recommendations are based on the valid application of sound financial theory, while those of Mr. Moul are not. Therefore, Staff recommends that the Commission adopt Ms. Freetly's recommendations, as outlined below, to set rates in this proceeding.

North Shore Gas Company				
		Percent of		Weighted
	Amount	Total Capital	Cost	Cost
Long-term Debt	$79,784,000	38.94%	4.13%	1.61%
Short-term Debt	$21,678,000	10.58%	0.74%	0.08%
Common Equity	$103,435,000	50.48%	9.00%	4.54%
Total Capital	$204,897,000	100.00%		
Weighted Average Cost of Capital				**6.23%**

The Peoples Gas Light and Coke Company				
		Percent of		Weighted
	Amount	Total Capital	Cost	Cost
Long-term Debt	$864,589,000	46.51%	4.26%	1.98%
Short-term Debt	$58,805,000	3.16%	0.91%	0.03%
Common Equity	$935,610,000	50.33%	9.00%	4.53%
Total Capital	$1,859,004,000	100.00%		
Weighted Average Cost of Capital				**6.54%**

VII. OPERATIONS

A. AMRP Main Ranking Index and AG-Proposed Leak Metric(s)

B. Pipeline Safety-Related Training (Uncontested)

Staff and Peoples Gas agree that the Commission's Order should state the following with respect to the test-year amount of pipeline safety-related training:

> The test year amounts of test year pipeline safety-related training for Peoples Gas are: $11,355 for Corrosion-NACE Levels 1 and 2 Certification; $80,500 for Parts 191 and 192 Training; $0 for Construction Inspection; $6,300 for all other pipeline safety-related training, totaling $98,135. (Staff Ex. 1.0, 27, NS-PGL Ex. 23.0 2nd REV., 11)

VIII. COST OF SERVICE

A. Overview

Both North Shore and Peoples Gas provided an embedded cost of service ("ECOS") study with their filings in their respective Exhibits 14.1-14.8. The ECOS studies identify the revenues, costs, and profitability for each class of service and are a partial basis for the Companies' proposed rate design. Generally, the Companies prepared the ECOS studies utilizing three major steps: (1) cost functionalization; (2) cost classification; and (3) cost allocation of all the costs of the utility's system to customer classes. (Staff Ex. 4.0, 6) Staff witness Johnson testified that he had no objection to the Companies' proposed ECOS studies to assign costs to the various functions and rate classes. (*Id*., 14)

AG/ELPC witness Scott Rubin recommended the Commission use the results of the Companies' ECOS studies as a guide to the allocation of costs among the customer classes and that the results of those studies should be used as a guide to designing rates. (AG/ELPC Ex. 9.0, 13:274-277.)

IIEC witness Brian Collins takes issue with the Companies' proposed ECOS studies' and proposes various adjustments. (IIEC Ex. 1.0, 2-3:38-41.)

B. Embedded Cost of Service Study

1. Allocation of Demand-Classified Transmission and Distribution Costs

The Commission should accept the Companies' proposed ECOS studies. These ECOS studies use largely the same cost allocation methodologies that were approved in the Companies' 2009, 2011, and 2012 rate cases. They are acceptable guidance for determining rates in this case.

IIEC witness Collins disagrees with the Companies' proposed average and peak ("A&P")[32] cost allocation methodology for allocating transmission and distribution ("T&D") mains. (IIEC Ex. 1.0, 2:38-41.) He instead proposes that the Coincident Peak ("CP")[33] cost allocation methodology be used. (*Id*., 9:161-163.) Mr. Collins provides two reasons why the A&P cost allocation method should be rejected. First, he states that the A&P cost allocation method double counts the "average" component of demand. Second, he opines that the A&P cost allocation method does not appropriately reflect how costs are incurred by the Companies. (IIEC Ex. 1.0, 2:42-51.)

Companies Witness Hoffman Malueg explained that the Companies have been using the A&P allocation methodology since ICC Docket No. 07-0241/07-0242 (cons.). NS-PGL Ex. 28.0, 4.) She also stated that while IIEC witness Collins continually asserts that the Utilities T&D system is designed to meet peak day demand, the Utilities explained repeatedly in data responses to the IIEC that peak day demand, while being the primary factor, is not the only factor the Companies consider when designing the system. (*Id*., 5.) With respect to Mr. Collins' contention that the A&P allocator is double counting, Ms. Hoffman Malueg disagrees with this concept and states that demand costs are attributable to both average use as well as peak demand. To align with this theory, the Average and Peak demand allocation method mathematically combines

[32] The A&P method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates costs to all classes of customers and tempers the apportionment of costs between the high and low load factor customers.

[33] The CP method, allocation is based on the demands of the various classes of customers at the time of system peak.

average usage and peak demand to appropriately allocate capacity costs based upon that cost causation method. Ms. Hoffman Malueg further explains that the Average and Peak demand allocation method also mathematically weights the portion of the allocator that is to be based upon average demand by the system load factor, further aligning the theory that it is premised upon. (*Id*., 6.)

Staff witness Johnson explained that Mr. Collins' argument fails to recognize that the A&P allocator serves two distinct purposes, to reflect class contributions to the system average and to the system peak. Accordingly, the A&P appropriately considers both average and peak demands in the allocation process. (Staff Ex. 9.0, 29.)

The Commission addressed this double counting argument by the IIEC in Docket No. 04-0476, Illinois Power Company's proposed general increase in natural gas rates. *Id*. The Commission concluded that:

> While the IIEC argues that the A&P method improperly double counts average demand in allocating T&D plant costs, the Commission believes that when allocating T&D plant costs an emphasis on average demand is appropriate. The record demonstrates that the A&P method relies upon class average demands and class coincident peak demands, which by definition are numerically larger than the associated averages.
>
> Illinois Power Company, ICC Order Docket No. 04-0476, 64-65 (May 17, 2005).

(*Id*., 30.)

Additionally, in Central Illinois Public Service ("CIPS") and Union Electric ("UE") proposed general increase in natural gas rates, the Commission stated:

> Furthermore, the Commission finds that the argument that the A&P method double counts average demand is not a sufficient basis for rejecting that approach. In fact, the Commission believes that when allocating demand costs it is

> the A&P method's emphasis on average costs rather than peak costs that justifies its adoption.

Central Illinois Public Service Company, ICC Docket Nos. 02-0798, 03-008 & 03-0009 (Cons.), 98 (October 22, 2003). *Id*.

In response to Mr. Collins' argument that the A&P cost allocation method does not appropriately reflect how costs are incurred by the Companies, Mr. Johnson explained that the A&P allocates costs by both peak demands and average demands. The peak demand component recognizes that a T&D system is sized to meet maximum annual demands. However, there is also an average demand component because meeting peak demands is not the sole factor that shapes investment in a T&D system. Another factor, but not the only factor, is the economic motivation to construct a T&D system. This is more appropriately reflected by average demands than peak demands. This is because year-round demands are necessary to generate sufficient revenues to justify investment in a T&D system. These year-round demands are reflected in the average demand but not the peak demand portion of the A&P allocator. *Id*.

Other factors are safety and reliability. Safety and reliability investments are more appropriately reflected in average demands. Safety and reliability are important, not just only for the peak day, but for every day of the year that gas is consumed which is what the average demand component reflects. (*Id*., 31.)

Additionally, there is strong precedent in Illinois for using the A&P demand allocator. *Id*. The Commission typically uses this allocation methodology for the distribution costs of gas companies. In Central Illinois Public Service Company ("CIPS") and Union Electric Company's ("UE")[34] proposed general increase in natural gas rates, Docket No. 04-0476, the Commission concluded:

> The allocation method that properly weights peak demand is the A&P method, the same method that the Commission adopted in CIPS' and UE's last gas rate cases. The A&P method properly emphasizes the average component to reflect the role of year-round demands in shaping transmission and distribution investments.
>
> Central Illinois Public Service Company, ICC Docket Nos. 02-0798, 03-008 & 03-0009 (Cons.), 98 (October 22, 2003).

The Commission also accepted the use of the A&P allocation methodology in Nicor Gas' 2004 rate case. Northern Illinois Gas Company, ICC Order Docket No. 04-0779, 102 (September 20, 2005) and Nicor Gas' most recent rate case Docket No. 08-0363.[35] The Commission subsequently directed Peoples Gas and North Shore to employ the A&P demand allocation methodology to allocate the distribution costs in Docket Nos. 07-0241/07-0242 (Cons.). North Shore Gas Company, ICC Order Docket No. 07-0241/07-0242 (Cons.), 199 (February 5, 2008). Since then, the Companies have employed the A&P demand allocation methodology in their COS studies. In each case, the A&P methodology was approved by the Commission. (*Id*., 32.)

AG/ELPC witness Rubin also disagrees with IIEC's proposal to eliminate the A&P allocator. Mr. Rubin indicated his understanding that the Commission has used this method (A&P) consistently for the Companies since at least 2007, and IIEC witness Collins does not present any new arguments or a compelling reason to change this well-established allocation method. Mr. Rubin also reviewed the rebuttal testimony of

[34] CIPS and UE are now part of Ameren Illinois Company.

[35] The A&P methodology was used again in Nicor Gas' 2008 rate case, Northern Illinois Gas Company, ICC Order Docket No. 08-0363, 72-77 (March 25, 2009).

Companies' witness Hoffman Malueg and agrees with her criticisms of Mr. Collins' testimony on this issue and concluded that IIEC failed to show that the Companies' use of the average and peak method is improper. (AG/ELPC Ex. 9.0, 12.)

2. Allocation of Small Diameter Main Service Costs

IIEC witness Brian Collins proposes to delineate the costs of mains smaller than 4 inches and allocate those costs to all classes except for the S.C. No. 4 class. He states that since all but three S.C. No. 4 customers do not utilize mains smaller than 4 inches in receiving service, this adjustment reflects cost causation. (IIEC Ex. 1.0, 21.)

Peoples Gas and North Shore’s engineering witnesses, David Lazzaro and Mark Kinzle respectively stated that smaller diameter mains support service to the S.C. No. 4 customers. In fact, the Companies design and operate their systems in an integrated manner. The fact that a customer is directly served by a main that is four-inches or greater does not mean that smaller diameter pipe is not useful or, in some instances, necessary, in serving that customer. Operating the system as an integrated whole enhances the reliability of service to all customers. For example, smaller diameter mains may backfeed the larger diameter main and support service to the S.C. No. 4 customer. A backfeed refers to an alternate flow path for the gas. This may be important when an outage occurs, resulting from, for example, required maintenance activity or third party damage to the Companies’ facilities. (NS-PGL Ex. 23.0, 11-12; NS-PGL Ex. 31.0, 4-5.)

Additionally, Companies witness Hoffman Malueg states that as shown within the Utilities’ responses to IIEC data requests, all service classifications portrayed in the

Utilities' ECOSSs receive service directly from all sizes of distribution mains. The only purpose of delineating between small and large distribution mains within the Utilities' ECOSSs would be to segregate costs such that they can be allocated to the service classifications differently. (NS-PGL Ex. 28.0, 9.) However, because all of the Utilities' service classifications are served from all sizes of distribution mains, there is no reason to delineate distribution mains within the ECOSSs. Additionally, the Utilities' witnesses Mr. David Lazzaro and Mr. Mark Kinzle within their rebuttal testimonies (NS-PGL Exs. 23.0 and 31.0, respectively) explain that the Utilities' distribution systems are an integrated network of various main sizes. Simply because a customer is directly served by a large distribution main does not preclude the fact that a small distribution main is useful in providing service to such customer. Given these reasons, it is not appropriate to delineate between small and large distribution mains within the Utilities' ECOSSs. *Id*.

AG/ELPC witness Rubin also addressed this issue and disagreed with the IIEC's proposal. Mr. Rubin stated that the IIEC ignores the fact that customers in the S.C. No. 4 class are served by mains in the 4 inch and smaller category, as the Companies indicated in several data request responses. Mr. Rubin opined that there was no factual support for IIEC's position on this issue. (AG/ELPC Ex. 9.0, 12.)

No other parties addressed this issue.

IX. RATE DESIGN

A. Overview

The Companies propose greater recovery of fixed costs through fixed charges. The Companies consider all of their costs recovered through base rates as fixed. (NS Ex. 15.0, 9; PGL Ex. 15.0 REV, 9.) Peoples Gas' classes are S.C. No. 1 Residential

Heating and Non-Heating, S.C. No. 2 General Service, S.C. No. 4 Large Volume Demand Service, S.C. No. 5 Contract service for electric generation, S.C. No. 7 Contract service to prevent bypass, and S.C. No. 8 Compressed Natural Gas Service. North Shore's classes are the same as Peoples Gas except North Shore does not have a No. 8 Compressed Natural Gas Service class. (PGL Ex. 15.0 REV, 15-19; NS Ex. 15.0, 15-19.) The Companies also propose changes to various miscellaneous charges. (PGL Ex. 15.0 REV, 10; NS Ex. 15.0, 10-11.)

Staff recommends the Commission: (1) begin the process of adjusting the Companies' rate designs away from a straight fixed variable ("SFV") based rate design for the S.C. No. 1 Residential Heating and Non-Heating classes and the S.C. No. 2 General Service class; (2) accept the Companies' proposed rate design for Peoples Gas and North Shore's S.C. No. 4 Large Volume Demand Service rate class; (3) accept the Company's proposed rate design for Peoples Gas' S.C. No. 8 Compressed Natural Gas Service; and (4) accept the Companies' proposed Service Activation Charges, Reconnection Charges, and Second Pulse Data Capability Charges. (Staff Ex. 4.0, 4-5.)

AG/ELPC witness Rubin recommends the Commission reject the Companies' rate design proposals. Instead he recommends that the Companies begin moving away from SFV pricing. (AG/ELPC Ex. 3.0, 3.)

IIEC witness Collins proposes an across-the board-increase. (IIEC Ex. 1.0, 3.)

B. General Rate Design

1. Allocation of Rate Increase

The Companies state that if the Commission approves a revenue requirement other than that proposed by the Companies, they will make the necessary adjustments to the appropriate ECOS studies accounts and allocators based on the findings in the Commission order in this proceeding. Assuming that the Commission approves the Companies' proposed rate design, the resulting allocation of the revenue requirement by rate and customer class from the ECOSS will then be used to set charges as discussed in the direct testimony of Companies witness Egelhoff and by using the formulas reflected in the supporting rate design work papers. (Staff Ex. 4.0, 25.)

Staff has no objection to the Companies' proposal to re-run the ECOS studies and adjust the rate design based upon the Commission's final Order. *Id*. The IIEC states that due to the flaws in the Companies' cost of service studies, it proposes an across the board increase. (IIEC Ex. 1.0, 24.)

The Companies disagree with IIEC's proposed across the board increase. The Companies state that they primarily base their rate design on the ECOSS. (NS-PGL Ex. 29.0 REV, 21.) Mr. Collins states that this across-the-board approach is supported by the modified cost of service studies sponsored by his colleague, Ms. Amanda M. Alderson, (IIEC Ex. 1.0, 25.). However, these cost of service studies contradict Mr. Collins' argument for an across-the-board increase because they show that each service class causes different allocations of the proposed revenue deficiencies. The Companies claim that IIEC has failed to provide support for an across-the-board increase or to address how these resulting costs should be used to set rates and that the IIEC has failed to offer any rates and bill impacts that would result if such an allocation were approved. In addition, the proposal would not result in cost-based rates for any service classification and would create cross-subsidization across service classifications. (NS-PGL Ex. 29.0 REV, 21-22.) Furthermore, the Companies state that

Mr. Collins has failed to address how his proposal would impact the recovery of cost based storage costs recovered under Rider SSC, Storage Service Charge, as well as the determination of baseline uncollectible amounts by service classification that are reconciled under Rider UEA, Uncollectible Expense Adjustment, for recovery of delivery related uncollectible accounts expense. Therefore, his proposal is incomplete and unsupported and should not be approved. (*Id*., 22.)

AG/ELPC witness Rubin dismisses IIEC's proposed across-the-board increase. Mr. Rubin states the IIEC witness Collins is the only witness who recommended any changes in the study. His changes are not appropriate, as they are neither supported by the facts nor consistent with the Commission's standard practice. Moreover, even if one of his recommendations were properly supported, that does not render the study itself to be flawed. (AG/ELPC Ex. 9.0, 13.) The AG/ELPC also stated that another IIEC witness (Ms. Alderson in IIEC Exhibit 2.0) had no trouble using the Companies' cost models to produce new results using Mr. Collins's assumptions. Thus, there is no basis for concluding that the Companies' cost-of service studies are "flawed" or unable to be modified to produce reliable results. *Id*.

2. Fixed Cost Recovery

The Commission should accept Staff's and the AG's recommendation to begin moving away from SFV-based rate design. The Commission's recent Orders in ComEd (Docket No. 13-0387) and Ameren Illinois (Docket No. 13-0476) make it clear that SFV-based rate designs should be re-examined and rate design should reflect traditional rate design principles, which more closely align customers' bills with the ECOS study. The

Commission is actively reevaluating how rate design can be utilized to ensure that customers are responsible for the demands they place on the system and that rate design maximizes conservation efforts.

Staff witness Johnson explained that traditionally, rate design aligned customer charges with the ECOS study customer costs and aligned per therm distribution charges with the ECOS study demand costs. (Staff Ex. 4.0, 20.) The Companies' proposals to increase fixed cost recovery through fixed charges (NS Ex. 15.0, 9 and PGL Ex. 15.0REV, 9.) is a SFV-based or modified SFV rate design that shifts recovery of some of the ECOS study demand related costs to the customer charge and away from the per therm distribution charge. The result reduces the effect of increased usage on the customers' bill. When a customer charge is based upon all of the ECOS study customer costs and part of the ECOS study demand costs, the resulting per therm distribution charge is lower than it would have been if all demand costs were recovered through the distribution charge. The Companies' rate design can encourage increased consumption through lower per therm distribution charges rather than discouraging it through higher per therm distribution charges. Thus, the price signal for ratepayers to conserve is weakened. (Staff Ex. 4.0, 20.)

Staff witness Johnson recommends the Commission move away from a SFV-based rate design. Mr. Johnson stated that in Docket No. 13-0387, the Commission adopted adjustments to ComEd's SFV-based rate design in Docket No. 13-0387, which moved away from SFV-based rate design through lower fixed cost recovery. (Staff Ex. 4.0, 16.) The rate design the Commission approved in the ComEd case set customer charges based upon the ECOS study's customer costs and demand charges based upon the ECOS study's demand costs. Commonwealth Edison Co., ICC Order Docket No. 13-0387, 68 (December 18, 2013). (Staff Ex. 4.0, 16-17.)

Additionally, in Ameren Illinois Company's ("Ameren") most recent revenue neutral electric rate design case (Docket No. 13-0476) the Commission directed Ameren to maintain the current percentage of fixed cost recovery through fixed charges (44.8%) for the DS 1 residential class, even though the Company requested an increase to 50% fixed cost recovery through a modified SFV rate design, with the expectation that the issue would be revisited in Ameren's next rate design proceeding. Ameren Illinois Company, ICC Order Docket No. 13-0476, 101-102 (March 19, 2014). The Commission referenced the ComEd rate design case when rejecting Ameren's proposal to move towards greater fixed cost recovery through a SFV-based rate design.

One of the main drivers the Commission noted behind its rejection of the AG's proposal to move away from SFV-based rates and significantly reduce the fixed cost recovery through fixed charges in the Ameren case was the potential to create rate shock for a significant number of electric space heating customers. While such concerns could have been addressed by a phased-in approach, the record was insufficient to implement such an approach. Therefore, the Commission did not adopt the AG's proposal, yet still rejected Ameren's proposal to increase fixed cost recovery through fixed charges in its proposed modified SFV rate design. Ameren Illinois Company, ICC Order Docket No. 13-0476, 102 (March 19, 2014). (Staff Ex. 4.0, 17-18.)

The Commission subsequently granted rehearing in 13-0476 to provide the Commission with additional evidence about the bill impacts of moving away from an SFV rate design for residential customers. Ameren Illinois proposed adopting a SFV rate design for the DS-1 class customer charge to recover 44.8% of the DS-1 revenue requirement from the monthly non-volumetric charges. The AG proposed a rate design through which the Company would recover approximately 28% of its revenue requirement through the non-volumetric charges. Ameren Illinois Company, ICC Order On Rehearing Docket No. 13-0476, 40 (September 30, 2014). The Commission reiterated its support for a discontinuation of the shift toward a greater SFV rate structure:

> Nothing presented in this rehearing changes the Commission's conclusion in the March 19, 2014 Order that there are policy reasons for adopting a rate design with greater emphasis on traditional ratemaking principles like cost causation. This decision is supported by the arguments made by the AG in this case including more equitable cost sharing within customer classes, rates that are consistent with the General Assembly's intent to promote energy conservation, and the fact that the Company's financial risk has been reduced as a result of its participation in EIMA. The Commission supports a rate design which encourages residential customers to reduce energy usage and increase energy efficiency. The record in this case supports a discontinuation of the shift toward a greater SFV rate structure as proposed by AIC. Ameren Illinois Company, ICC Order On Rehearing Docket No. 13-0476, 41 (September 30, 2014).

The Commission ultimately accepted Staff's proposal that continues the movement away from a SFV rate design and shifts to a rate design that decreases the fixed customer charge and increases the variable charges, while protecting against the potential for significant bill impacts, as initially contemplated in the original 13-0476 March 19th Order. Ameren Illinois Company, ICC Order On Rehearing Docket No. 13-0476, 42 (September 30, 2014).

These recent Commission orders adopt rate designs that move away from a SFV-based rate design and instead align customers' bills with the cost of service (i.e., customer charges based upon ECOS study customer costs and distribution/demand charges based upon ECOS study demand costs). (*Id*., 19.) It is clear the Commission is considering how rate design can be utilized to ensure that customers are responsible for the demands they place on the system and that rate design maximizes conservation efforts. Additionally, the Commission is weighing the effects of the Energy Infrastructure Modernization Act ("EIMA") on revenue stability in the electric industry and the gradualism needed in adjusting SFV-based rate design because of potential rate shock. *Id*.

Mr. Johnson also stated that, similar to ComEd's and Ameren Illinois' participation in EIMA, which the Commission found reduces financial risk, Peoples Gas and North Shore have implemented a Volume Balancing Adjustment Rider ("Rider VBA") which stabilizes the distribution revenue requirement approved by the Commission in the Company's most recent rate proceeding. (Peoples Gas, ILL.C.C. No. 28, Sheet Nos. 61-63 and North Shore, ILL.C.C. No. 17, Sheet Nos. 60-62.) Peoples Gas has also implemented a Qualifying Infrastructure Plant Surcharge ("Rider QIP"), which allows the Company to recover a return on, and depreciation expense related to, the Company's investment in qualifying plant since the Company's last rate case. (Peoples Gas, ILL.C.C. No. 28, Sheet No. 130-138.2.) Both of these riders are rate recovery mechanisms that mitigate concerns regarding revenue stability. (*Id*., 19-20.)

Additionally, Mr. Johnson stated that the Companies' proposed rate design could negatively affect equitable cost sharing within customer classes. He explained how the Companies' ECOS studies take functional costs and further classify them by cost causation into commodity related, demand related, and customer related. Each class is then assigned commodity, demand, and customer related costs. Adoption of the Companies' rate design would create inconsistency between how costs are caused and how revenues are collected. For example, the Companies' proposed SFV-based rate design recovers some demand related costs, such as distribution mains, through the customer charge and therefore shifts cost recovery from a per therm basis to a per customer basis. (Staff Ex. 4.0, 21.) The inconsistency arises because assigning demand related costs to the customer charge assumes each customer in the class contributes equally to the class demand. There is no evidence in the record to support this assumption. Furthermore, that assumption is inconsistent with the way demand costs are allocated among the customer classes. Demand related costs are allocated among customer classes based on demand, not based upon the assumption that each customer contributes equally to demand.

The Companies state that if the Illinois Supreme Court issued an adverse ruling concerning Rider VBA,[36] then the Companies would propose a 100% SFV rate design. (PGL Ex. 15.0 REV, 13:266-269 and NS Ex. 15.0, 13:266-269.) However, a 100% SFV rate design would entail a fixed monthly customer charge and no volumetric distribution charge. (PGL Ex. 15.0 REV, 14-15:303-305 and NS Ex. 15.0, 15:304-306.) Therefore, all demand related costs would be recovered through the customer charge. This contingent 100% SFV proposal not only suffers the same deficiencies as the Companies' primary SFV-based proposal discussed previously, but it magnifies the

[36] On March 29, 2013 the Illinois Appellate Court (2nd district) issued a decision affirming the Commission's adoption of Rider VBA. The Illinois Supreme Court granted the Attorney General's Petition for Leave to Appeal.

impact of those deficiencies because it would shift recovery of all demand related costs to a flat customer charge regardless of each customer's contribution to the class demand. So, for example, a residential customer in a 1,000 square foot home would pay the same amount for distribution mains as a larger residential customer residing in a 4,000 square foot home with much greater heating demands, despite the fact that the 4,000 square foot home could be expected to utilize a larger share of main capacity for its gas requirements. (Staff Ex. 4.0, 21-22.)

AG/ELPC witness Rubin also recommends that the Commission reject the Companies' proposals to move closer to straight fixed-variable rate design. He states that moving towards SFV rate design would create inequities and cross-subsidies within the residential space heating class. He also concludes that SFV rate design is unnecessary, given the use of other rate mechanisms to achieve revenue stability, and that it is contrary to the State's energy efficiency policies. (AG/ELPC Ex. 3.0, 3:61-67.)

The Companies' responded that all of their costs (ECOS study customer and demand costs) are fixed and that fixed costs should be recovered through the customer charge for S.C. No. 1 and S.C. No. 2 classes. Companies' witness Egelhoff states that the Commission has endorsed policies in several rate proceedings to increase the fixed cost recovery through fixed charges. With respect to demand costs alone, Ms. Egelhoff states that demand costs, by definition, are driven by customer demand on the peak day. (NS-PGL Ex. 29.0 REV, 7.) The infrastructure that is put in place to handle the demand will cost the same regardless of the amount of demand that is placed on the system at any given time. (*Id*., 8.)

Ms. Egelhoff's statement misses the point. The relevant question here is not the cost of the infrastructure built to meet demand but rather who should pay for it. If demand costs are recovered through the customer charge, all customers are assumed to cost the same for the Companies to serve them. (Staff Ex. 9.0, 7.) If demand costs are recovered through the distribution charge, the recovery method assumes the costs are not the same for all customers to serve them. If demand costs are recovered through the distribution charge, that assumes that customers with higher usage will have higher peak demands and be more costly to serve than small use customers. While this latter assumption may not be true in each and every case, it is more reasonable than the Companies' proposed rate design's implied assumption that all customers within a class cause the utility to incur the same amount of demand costs. A customer with a 4,000 square foot home would be expected to place greater demands on the system at the peak compared to the customer with a 1,000 square foot home. Recovering demand costs through the customer charge does not recognize this difference. *Id*.

Staff also observed that the Companies' approach does not encourage conservation as much as Staff's rate design, which recovers a greater share of costs through variable charges and thereby increases the financial incentive for customers to adopt conservation measures. Although gas costs comprise a portion of a customer's total monthly gas bill, the customer is still concerned about the total bill. Recovering distribution demand costs on a per therm basis increases the incentive to conserve. In contrast, the Companies' rate design recovers some of the demand costs on a per customer basis instead of a per therm basis. This causes the distribution charge to be lower compared to if all of the demand costs were recovered on a per therm basis. Thus, the price signal for ratepayers to conserve is weakened. (Staff Ex. 9.0, 8.)

In a report to the Illinois General Assembly, the Commission recently addressed the issue of energy conservation cost recovery. The Commission stated that:

> A recent ruling by the 2nd Circuit Court of Appeals upheld a Commission tariff that permitted Peoples and North Shore Gas to reconcile over or under recovery of revenues resulting from deliveries being higher or lower than anticipated. The result of this ruling is that the Commission can provide a mechanism for revenue stability that *lowers the monthly customer charges and increases the volumetric charges. Such a change can decrease energy use by providing a greater price signal without affecting the overall bill to an average retail customer*[37]*.*
>
> (Illinois Commerce Commission, Report To the Illinois General Assembly Concerning Coordination Between Gas and Electric Utility Energy Efficiency Programs and Spending Limits For Gas Utility Energy Efficiency Programs, August 30, 2013, 22-23.) (Emphasis added.)

(Id., 8-9)

This excerpt from the report demonstrates that the Commission has recognized that lower monthly customer charges and higher volumetric charges (per therm distribution charge) can decrease energy use by providing a greater price signal. Staff's rate design proposal, which lowers the customer charge and increases the volumetric charge compared to the Companies' proposals, encourages energy conservation to a greater extent than the Companies' proposal would. *Id*.

[37] The Commission would need to evaluate the merits of such a change on a utility by utility basis as rate cases are filed.

C. Service Classification Rate Design

1. Uncontested Issues

a. Service Classification No. 8, Compressed Natural Gas Service (PGL)

North Shore does not currently have a Compressed Natural Gas Service class. Peoples Gas is proposing to set the S.C. No. 8 Compressed Natural Gas Service class at cost. (PGL Ex. 15.0, 19.) Seventy-five percent of total customer costs are recovered through the customer charge under the Company's proposal compared to the current 50%. The Company is taking a gradual approach for bill impact reasons. (Staff Ex. 4.0, 62.) The revenues in total from all charges will recover the full cost to serve the customers. The S.C. No. 8 class is available to any customer for gas to be used as compressed natural gas to fuel a vehicle. *Id*.

Staff has no objection to Peoples Gas' rate design proposal for the S.C. No. 8 rate class. Staff opined that it is important that the S.C. No. 8 rates reflect the full class cost of service so customers can make informed decisions concerning their use of natural gas in vehicles and their possible purchases of natural gas vehicles. (*Id*, 63.)

No other party provided written testimony addressing the S.C. No. 8 class.

b. S.C. No. 5 Contract Service for Electric Generation and S. C. No. 7 Contract Service to Prevent Bypass

The Companies are not proposing any changes to these classes. (NS Ex. 15.0, 19; PGL Ex. 15.0 REV, 19.) Both classifications are contract services whereby the prices to be paid and the terms and conditions of service are mutually agreed upon and are negotiated pursuant to special contracts. Staff had no objection. (Staff Ex. 4.0, 44, 63.)

No other party provided written testimony addressing these classes.

2. Contested Issues – North Shore and Peoples Gas

a. Service Classification No. 1, Small Residential Service, Non-Heating

The Commission should accept Staff's proposal to have the Companies begin the process of moving away from SFV-based rate design. By assuring that the S.C. 1 NH class' customer charge reflects ECOS study-based customer costs only, the Commission can start the movement away from SFV-based rates for North Shore and Peoples Gas and ensure that customers are instead paying for the ECOS study-based costs they cause.

The Companies propose fixed customer charges for North Shore and Peoples Gas that recover 90% of non-storage related fixed costs through the customer charge. The Companies also propose a flat distribution charge per therm for sales and transportation customers. (NS Ex. 15.0, 11; PGL Ex. 15.0REV, 11.)

Staff witness Johnson found that the Companies' total customer charge revenues derived from their proposed customer charges reflect approximately 97% of the total ECOS study-based customer costs for the Companies. Therefore, under the Companies' proposal, customers in the S.C. No. 1 NH class would pay for ECOS study-based customer costs in the customer charge and ECOS study-based demand costs in the single block distribution charge. This methodology is consistent with the rate design the Commission approved in ComEd Docket No. 13-0387 and favored in Ameren Docket No. 13-0476. Therefore, Staff witness Johnson has no objection to the proposed customer charge and flat distribution charge recommended by the

Companies. They both recover their individual ECOS study-based costs. (Staff Ex. 4.0, 26-27, 45)

However, Mr. Johnson's agreement with the Companies' proposed customer charge and flat distribution charge is not an acceptance of the Companies' theory for their proposed SFV-based rate design with 90% fixed cost recovery. If North Shore's total customer charge revenues derived from the proposed customer charge ($15.80) are greater than the customer costs found on the final Commission approved ECOS study in this proceeding, then the final customer charge should be lowered to recover ECOS study-based customer costs only. Likewise if Peoples Gas' total customer charge revenues derived from the proposed customer charge ($16.70) are greater than the customer costs found on the final Commission approved ECOS study in this proceeding, then the final customer charge should be lowered to recover ECOS study customer costs only. Any remaining revenues for either Company would be collected through the flat distribution charge. (*Id*., 27:45-46.) Staff's proposed rates, which are based upon the Companies' proposed direct testimony revenue requirement (Staff Ex. 4.0, 24.), can be found at ICC Staff Ex. 4.0, Schedule 4.01N and Schedule 4.01P.

In rebuttal testimony, the Companies opposed Staff's conditional approval that the Utilities' total customer charge revenues derived under the Utilities' proposed rate designs and the final Commission approved ECOS studies should not result in more than customer cost recovery through the customer charge. Companies witness Egelhoff stated that all of the Companies' costs recovered through base rates are fixed. (NS-PGL Ex. 29.0 REV, 15.)

Staff witness Johnson responded that the Companies' position reflects the overall disagreement on whether the customer charge should recover only customer costs (traditional rate design) or include costs related to customer demands (100% SFV or SFV-based). As Staff discussed in direct testimony, the Commission is moving away from an SFV-based rate design and back to a more traditional rate design approach, i.e., all demand-related costs are recovered through the variable charge and all customer-related costs are recovered through fixed charges. The Commission's recent Orders make it clear that SFV-based rate designs should be re-examined and rates should reflect traditional rate design principles, which more closely align customers' bills with the ECOS study. (Commonwealth Edison Co., ICC Order Docket No. 13-0387, 75 (December 18, 2013 and Ameren Illinois Company, ICC Order Docket No. 13-0476, 101 (March 19, 2014) (Staff Ex. 9.0, 12.)

Staff witness Johnson opined that a traditional rate design approach more closely aligns rates with cost causation principles. As discussed under the Fixed Cost Recovery section above, if demand costs are recovered through the customer charge, all customers are assumed to cost the same to serve. If demand costs are recovered through the distribution charge, the cost to serve each customer is based upon usage. While both cost recovery methods are not exact, recovering demand costs through the distribution charge takes into consideration that customers do place different costs on the system. *Id*.

AG/ELPC witness Rubin is proposing that PGL and NS move toward collecting no more than 50% of its heating revenues, and no more than 75% of its non-heating revenues from the customer charges. (AG/ELPC Ex. 3.0, 22:470-471 and 29:579-580.)

Mr. Rubin states that under PGL's proposed revenue requirement, the 50% and 75% results can be approximated by keeping PGL's heating and non-heating customer charges at their existing amount. Thus, the increase would be collected solely through increases in the volumetric charges. (*Id*., 22.)

For NS, Mr. Rubin states that under North Shore's proposed revenue requirement the effects on larger-use heating customers might be severe if the change were made in one step, so Mr. Rubin recommends the residential customer charges should remain at their existing amounts. (*Id*., 29.)

Staff witness Johnson stated that it is not clear how Mr. Rubin derived the figures of 50% and 75% for heating and non-heating, respectively. Mr. Rubin states that PGL's ECOS study shows that 64% of heating costs are customer related and 93% of non-heating costs are customer related. (*Id*., 16.) He also states that NS' ECOS study shows that 67% of heating costs are customer related and 93% of non-heating costs are customer related. (*Id*., 27.) Mr. Rubin emphasizes that these are the maximum amount of costs that should be collected through the customer charge because the percentages from the ECOS studies assume that it is proper to recover all distribution-related costs that are classified as customer-related through the customer charge. He argues that traditionally NS and PGL collected a portion of those customer-related distribution costs through a volumetric charge. (*Id*., 16 and 26-27.) However, Mr. Rubin has not provided any type of evidence to justify that the distribution-related costs that are classified as customer-related should just be classified as distribution-related. (Staff Ex. 9.0, 24.)

Staff also stated that it is also not clear whether the 50% and 75% figures are based upon Mr. Rubin's assumption that the ECOS study distribution-related costs recovered through the customer charge should be recovered through the volumetric charge or are based upon some other reason. Therefore, Staff witness Johnson stated that he continues to recommend that the Commission accept Staff's rate design proposal as set forth in direct testimony. *Id*.

IIEC witness Brian Collins proposes an across-the-board increase for all classes. (IIEC Ex. 1.0, 3; IIEC Ex. 3.0, 18-19.)

b. Service Classification No. 1, Small Residential Service, Heating

The Commission should accept Staff's proposal to set the S.C. No. 1 Heating classes' customer charges to recover ECOS study customer costs and set distribution charges to recover ECOS study demand costs.

North Shore is proposing to increase the recovery of fixed costs in its SFV-based rate design to recover 80% of non-storage related fixed costs through the customer charge, compared to the current 68%[38] fixed cost recovery, with all remaining costs being recovered through a flat distribution charge. The monthly customer charge would increase from $23.75 to $29.55 and the distribution charge would decrease from 10.385 cents per therm to 7.133 cents per therm. This is applicable to both sales and transportation customers. (NS Ex. 15.4.) Peoples Gas is proposing to increase the recovery of fixed costs in its SFV-based rate design to recover 75% of non-storage

[38] North Shore Gas Company, ICC Order Docket No. 12-0511/12-0512 (Cons.), 237 (June 18, 2013).

related fixed costs through the customer charge, compared to the current 61%[39] fixed cost recovery, with all remaining costs being recovered through a flat distribution charge. The monthly customer charge would increase from $26.91 to $38.50 and the distribution charge would decrease from 18.885 cents per therm to 14.919 cents per therm. This is applicable to both sales and transportation customers. (PGL Ex. 15.4.)

Staff witness Johnson's assessment of the Companies proposal found that North Shore's proposed customer charge would recover approximately $51,355,507 in total annual customer charge revenues while the ECOS study identifies only $43,452,183 in customer costs for the S.C. No.1 HTG class. He found Peoples Gas' proposed customer charge would recover approximately $303,291,027 in total annual customer charge revenues while the ECOS study identifies only $254,928,725 in customer costs for the S.C. No.1 HTG class. (Staff Ex. 4.0, 28:47.) Mr. Johnson opined that these proposals are inconsistent with the Commission's recent orders, which adopt rate designs that move away from an SFV-based rate design and instead align customers' bills with the cost of service (i.e., customer charges based upon ECOS study customer costs and distribution\demand charges based upon ECOS study demand costs). (*Id.*, 29:47.) Staff's proposed rate design which sets customer charges based upon ECOS study customer costs and distribution charges based upon ECOS study demand costs would consist of a $25 monthly customer charge and 11.544 cents per them distribution charge for North Shore and a $32.35 monthly customer charge and 22.063 cents per therm distribution charge for Peoples Gas. (NS-PGL Ex. 29.0 REV, 17-18.) Staff's

[39] Peoples Gas Light and Coke Company, ICC Order Docket No. 12-0511/12-0512 (Cons.), 237 (June 18, 2013.

proposed rates are based upon the Companies' proposed direct testimony revenue requirement. (Staff Ex. 4.0, 24.)

Moreover, Staff found that since the Companies' proposed customer charges are based upon all ECOS study customer costs and part of the demand costs, the resulting lower distribution charge results in those customers that are incurring greater demands on the system to not paying their fair share. This occurs because under the Companies' proposal, demand costs are recovered through the customer charge, thereby shifting cost recovery from a per therm basis to a per customer basis. The lower-use heating customers in effect would subsidize the larger-use heating customers. (*Id*., 29:47-48.)

Finally, Staff stated that decreasing the distribution charge when the ECOS study indicates that all of the demand costs are not reflected in the distribution charge is inconsistent with the Commission's previously stated concerns regarding energy conservation.[40] In order to reflect the proper price signal and encourage energy conservation, the distribution charge should reflect all demand related costs so that those customers who place greater demands on the system pay for those demands. *Id*.

In the rebuttal stage of this proceeding the Companies responded the same as they did to Staff's proposal for the S.C. No. 1 non-heating class. That is, Ms. Egelhoff states that all of the Companies' costs recovered through base rates are fixed and that the cost of having infrastructure in place to handle that demand does not vary based on a customer's use. (NS-PGL Ex. 29.0 REV, 17.)

Staff witness Johnson provided the same response as what was put forth about the S.C. No. 1 non-heating class. Which is that recent Commission Orders indicate a

[40] Ameren Illinois, ICC Order Docket No. 13-0476, 101 (March 19, 2014).

movement away from SFV-based rate designs, especially for those utilities with cost recovery mechanisms in place (like the Companies' Rider VBA) that provide revenue stability. Staff's rate design proposal makes a similar movement while taking rate impacts into consideration. (Staff Ex. 9.0, 14.)

AG/ELPC witness Rubin is proposing that PGL and NS move toward collecting no more than 50% of its heating revenues, and no more than 75% of its non-heating revenues from the customer charges. (AG/ELPC Ex. 3.0, 22:470-471 and 29:579-580.) Mr. Rubin states that under PGL's proposed revenue requirement, the 50% and 75% results can be approximated by keeping PGL's heating and non-heating customer charges at their existing amount. Thus, the increase would be collected solely through increases in the volumetric charges. (*Id*., 22.)

For NS, Mr. Rubin states that under North Shore's proposed revenue requirement the effects on larger-use heating customers might be severe if the change were made in one step, so Mr. Rubin recommends the residential customer charges should remain at their existing amounts. (*Id*., 29.)

Staff witness Johnson stated that it is not clear how Mr. Rubin derived the figures of 50% and 75% for heating and non-heating, respectively. Mr. Rubin states that PGL's ECOS study shows that 64% of heating costs are customer related and 93% of non-heating costs are customer related. (*Id*., 16.) He also states that NS' ECOS study shows that 67% of heating costs are customer related and 93% of non-heating costs are customer related. (*Id*., 27.) He emphasizes that these are the maximum amount of costs that should be collected through the customer charge because the percentages from the ECOS studies assume that it is proper to recover all distribution-related costs that are classified as customer-related through the customer charge. He argues that traditionally NS and PGL collected a portion of those customer-related distribution costs through a volumetric charge. (*Id*., 16 and 26-27.) However, he has not provided any type of evidence to justify that the distribution-related costs that are classified as customer-related should just be classified as distribution-related. (Staff Ex. 9.0, 24.)

Staff also stated that it is also not clear whether the 50% and 75% figures are based upon Mr. Rubin's assumption that the ECOS study distribution-related costs recovered through the customer charge should be recovered through the volumetric charge or are based upon some other reason. Therefore, Staff witness Johnson stated that he continues to recommend that the Commission accept Staff's rate design proposal as set forth in direct testimony. *Id*.

IIEC witness Brian Collins proposes an across the board increase for all classes. (IIEC Ex. 1.0, 3 and IIEC Ex. 3.0, 18-19.)

c. Service Classification No. 2, General Service

The Commission should adopt Staff's S.C. No. 2 class proposal. Unlike the Company's proposal, Staff's rate design proposal takes into consideration: the Company's Rider VBA; the Commission's recent decisions that reflect movement away from greater fixed cost recovery through an SFV-based rate design; the negative effects the Company's proposed SFV-based rate design can have on conservation efforts; and equitable cost sharing (subsidization) within customer classes. Staff is proposing a gradual shift that takes into consideration customer bill impacts and revenue stability for the Company. The shift to greater fixed cost recovery through SFV-based rates has occurred over several rate cases and if the Commission chooses to move away from SFV-based rates, it should also do so in a gradual fashion.

North Shore currently has three meter classes based upon cubic feet of gas used per hour (i.e., Meter Class 1 - up to 700 cubic feet per hour, Meter Class 2 - over 700 and no more than 2300 cubic feet per hour, and Meter Class 3 - over 2,300 cubic feet per hour). North Shore proposes to recover 100% of ECOS study-based customer costs through the customer charge. In addition, it is proposing that the customer charge also recover 60% of non-storage related ECOS study-based demand costs for Meter Class 1 and Meter Class 2. Meter Class 3 will recover 45% of non-storage related ECOS study-based demand costs through the customer charge. The Company proposes that the monthly Meter Class 1 customer charge increase from $27.00 to $28.90; Meter Class 2 increase from $80.19 to $97.25; and, Meter Class 3 increase from $224.27 to $278.50. (NS Ex. 15.4.) The Company is also proposing to move from a declining three-block distribution charge to a declining two-block distribution charge. (NS Ex. 15.0, 17)

Peoples Gas currently has three meter classes based upon cubic feet of gas used per hour (i.e., Meter Class 1 - up to 700 cubic feet per hour, Meter Class 2 - over 700 and no more than 3000 cubic feet per hour, and Meter Class 3 - over 3,000 cubic feet per hour). Peoples Gas proposes to recover 100% of ECOS study-based customer costs through the customer charge. In addition, it is proposing that the customer charge also recover 45% of non-storage related ECOS study demand costs for Meter Class 1 and 50% for Meter Class 2. Meter Class 3 will recover 15% of non-storage related ECOS study demand costs through the customer charge. (PGL Ex. 15.0, 16-17:343-

349.) The Company proposes that the monthly Meter Class 1 customer charge increase from $36.12 to $41.00; Meter Class 2 increase from $118.92 to $152.85; and, Meter Class 3 increase from $310.31 to $435.70. (PGL Ex. 15.4.) The Company is also proposing to move from a declining three-block distribution charge to a declining two-block distribution charge. (PGL Ex. 15.0, 17.)

Staff found that the Companies' proposal to recover 100% of ECOS study-based customer costs through the customer charge for all three meter classes is appropriate. However, Staff reiterates that recent Commission orders have been moving towards aligning customers' bills with the cost of service (i.e., customer charges based upon ECOS study customer costs and distribution\demand charges based upon ECOS study demand costs). While the Companies' proposed customer charge recovers 100% of ECOS customer costs, it also recovers demand related costs. This is a shift towards greater SFV-based rate design and is, thus, problematic. The Commission has recently been making adjustments that move away from SFV-based rate designs for those electric companies that have adopted formula rates through EIMA. Similar to the impact of electric companies' formula rates, the Company's implementation of Rider VBA provides revenue stability and eliminates the need to have an SFV-based rate design. Also, increasing the percentage of non-storage related demand costs through fixed charges lowers the percentage of non-storage related demand costs recovered through the per therm distribution charge. This, in turn, could discourage conservation. (Staff Ex. 4.0, 33-34.) Finally, Staff found that moving ECOS study-based demand costs that are allocated to customer classes based upon demand into a fixed customer charge shifts cost responsibility to customers with lower demands. This occurs because rather than collecting total demand related costs on a per therm basis, some of the demand related costs are collected on a per customer basis. The per therm charge is lower than it would have been if all demand related costs were recovered on a per therm basis and the customer charge is higher than it would have been if the demand costs were collected through a per therm charge (For example, a customer that uses zero therms would pay for some of the demands that a larger use customer places on the system). *Id*.

Staff's proposed customer charge for all three meter classes (for each Company) will recover 100% of ECOS study-based customer costs. Consistent with the most recent Commission orders concerning movement away from SFV-based rate designs, Staff witness Johnson proposes a decrease in the percentage of non-storage related demand costs currently recovered through the customer charge for all three meter classes. His proposal provides a gradual shift away from SFV-based rate design while taking into consideration customer bill impacts and revenue stability for the Company. Specifically, Staff proposes the percentage of non-storage related demand costs recovered through the customer charge for North Shore for Meter Classes 1 and 2 be decreased by 10% from the current Commission approved 45%. The resulting percentage of non-storage related demand costs recovered through North Shore's customer charge for Meter Classes 1 and 2 would be 40%.[41] The same 10% decrease for North Shore's Meter Class 3 would result in a decrease in the percentage of non-storage related demand costs recovered through the customer charge from 35% to

[41] 40% ≈ 45% - (45% X 10%).

31%.[42] Staff's proposed customer charge for North Shore's Meter Class 1 would decrease from $27 to $26.10. Meter Class 2 would increase from $80.19 to $82.30 and Meter Class 3 would increase from $224.27 to $233.70. The remaining non-storage related demand costs would be recovered through the Company's proposed declining two-block per therm rate design. (Staff Ex. 4.0, 35-36 and Schedule 4.01N.)

For Peoples Gas, Staff proposes the percentage of non-storage related demand costs recovered through the customer charge for Meter Classes 1, 2, and 3 be decreased by 10% from the current Commission approved 40%, 45%, and 10%, respectively. The resulting percentage of non-storage related demand costs recovered through the customer charge for Peoples Gas would be 36% for Meter Class 1,[43] 40% for Meter Class 2,[44] and 9% for Meter Class 3.[45] Staff's proposed customer charge for Peoples Gas Meter Class 1 would increase from $36.12 to $38.10. Meter Class 2 would increase from $118.92 to $136.40 and Meter Class 3 would increase from $310.31 to $373.75. The remaining non-storage related demand costs would be recovered through the Company's proposed declining two-block per therm rate design. (*Id.*, 54-55 and Schedule 4.01P.)

Staff also recommends that, going forward, the Commission make additional adjustments to the percentage of non-storage related demand costs recovered through the customer charge until the customer charges per meter class recover only ECOS study customer costs. Staff is not recommending that a set percentage in each case or

[42] 31% ≈ 35% - (35% X 10%).

[43] 36% ≈ 40% - (40% X 10%).

[44] 40% ≈ 45% - (45% X 10%).

[45] 9% ≈ 10% - (10% X 10%).

time period be utilized to eliminate the non-storage related demand costs from the customer charge going forward. The amount of the adjustments should be decided in each case in order to consider bill impacts for customers. (Staff Ex. 4.0, 36:54-55.)

In addition, so the Commission has information about a broader range of bill impacts, Staff calculated rates and bill comparisons under three different scenarios in addition to Staff's proposed 10% reduction in non-storage related demand costs recovered through the customer charge. The three scenarios present differing levels of non-storage related demand costs that are recovered through the customer charge. In Scenario 1, rates (Table 1 NS and Table 4 PGL, Staff Ex. 4.0, 40-41 and 59) and bill comparisons (ICC Staff Ex. 4.0, Schedule 4.03N, page 1-3 and Schedule 4.03P pages 1-3) assume that the percentage of non-storage related demand costs recovered through the customer charge for S.C. No. 2 Meter Classes 1, 2, and 3 remain the same as the current meter class percentages.

In Scenario 2, rates (Table 2 NS and Table 5 PGL, Staff Ex. 4.0, 41 and 59-60) and bill comparisons (ICC Staff Ex. 4.0, Schedule 4.04N, pages 1-3 and Schedule 4.04P, pages 1-3) assume that the percentage of non-storage related demand costs recovered through the customer charge for S.C. No. 2 Meter Classes 1, 2, and 3 are reduced by 25% from the current Commission approved meter class percentages.

In Scenario 3, rates (Table 3 NS and Table 6 PGL, Staff Ex. 4.0, 42 and 60) and bill comparisons (ICC Staff Ex. 4.0, Schedule 4.05N, pages 1-3 and Schedule 4.05P, pages 1-3) assume that the total customer charge revenues, by meter class, are equal to the ECOS study customer costs; therefore, no ECOS study non-storage related demand costs are recovered through the customer charge.

In the rebuttal stage of this proceeding the Companies responded the same as they did to Staff's proposal for the S.C. No. 1 heating and non-heating classes. That is, Ms. Egelhoff states that all of the Companies' costs recovered through base rates are fixed and that the cost of having infrastructure in place to handle that demand does not vary based on a customer's use. (NS-PGL Ex. 29.0 REV, 19.) However, the Companies did state that if the Commission decides not to increase the fixed cost recovery in the fixed customer charge, then the Utilities propose the Commission should keep the fixed cost recovery for S.C. No. 2 unchanged from the present rate design, which is Staff's Scenario 1. (NS-PGL Ex. 29.0 REV, 20.)

IIEC witness Brian Collins proposes an across the board increase for all classes. (IIEC Ex. 1.0, 3 and IIEC Ex. 3.0, 18-19.)

No other party addressed the S.C. No. 2 class.

d. Service Classification No. 4, Large Volume Demand Service

The Commission should accept Staff's S.C. No. 4 rate design proposal.

The Companies are proposing to set the monthly customer charge at cost to recover all ECOS study customer costs. The customer charge increases from $594 to $656 per month for North Shore and the $687 to $982 for Peoples Gas. The proposed demand charge increases from 55.277 cents per therm of billing demand to 67.695 cents per therm for North Shore and 71.421 cents per therm of billing demand to 99.482 cents per them for Peoples Gas. The distribution charge recovers the remaining non-storage related demand costs for both Companies. (NS Ex. 15.0, 19 and PGL Ex. 15.0REV. 19.)

Staff witness Johnson has no objection to the Company's rate design proposal for the S. C. No. 4 rate class. The Company is proposing to set the customer charge at cost, which is a minimal part of a customer's bill since customers must use an average of over 41,000 therms per month and the customer charge would represent a minimal part of the total bill. The remaining revenues are collected through the demand and distribution charges and the S.C. No. 4 class proposal will recover its full cost of service. However, Mr. Johnson does propose that if the Company's total customer charge revenues derived from the proposed customer charge ($656 NS and $982 PGL) are greater than the customer costs found on the final Commission approved ECOS study, then the final customer charge should be lowered to recover ECOS study customer costs only. (Staff Ex. 4.0, 43:61-61.)

IIEC witness Brian Collins proposes an across the board increase for all classes. (IIEC Ex. 1.0, 3 and IIEC Ex. 3.0, 18-19.)

3. Classification of SC No. 1 Residential Heating and Non-Heating Customers

AG/ELPC witness Rubin testified that there may be residential customers who are misclassified as between heating and non-heating. (AG/ELPC Ex. 3.0, 3.) He states that if customers are misclassified between heating and non-heating classes there could be a large difference in the bills they pay. He gives an example of the rate difference between classifications for Peoples Gas. The non-heating customer charge under present rates is $13.60 per month and the per therm delivery charge is $0.42032. The heating customer charge is $26.91 per month and the per therm delivery charge is $0.18885. (*Id*., 11.) The AG/ELPC recommends that the Companies investigate and improve the classification of residential customers and report back to the Commission on its findings. AG/ELPC witness Rubin further recommends that if the Companies cannot complete the process by the close of the record in this case, or if they refuse to undertake the task, then the Commission should order the Companies to do so as quickly as possible following the conclusion of this case. (*Id*., 13-14.)

Companies witness James Robinson responded that the Utilities have long-standing processes, pre-dating the introduction of heating and non-heating rates in S.C. No. 1, to identify the customer's appliances. These processes involve both inquiries when an applicant or customer interacts with a customer service representative or a physical inspection of the premises. For example, as part of the service turn-on procedure, the customer service representative will verify the appliances with the applicant. Appliances include a range, central heating plant, automatic water heater, space heater, boiler and any other-gas fired equipment. Generally, when an applicant calls to initiate service, the default designation is the existing or previous account type. If the customer service representative receives information that is inconsistent with that designation, this will trigger a field order for physical confirmation at the premises. Thus, for example, if Apartment 123 is classified as a heating account with a boiler, but the applicant states that he has only non-heating appliances, this triggers a field order. When the utility changes out or installs a meter, this requires a physical inspection of the premises and a verification of appliances. (NS-PGL Ex. 32.0, 7.)

If a customer is seeking low income home energy assistance program ("LIHEAP") funding but his account is a non-heating account, this will trigger a physical inspection to verify the appliances, as non-heating accounts are not eligible for LIHEAP. (*Id*., 8.)

For new construction, the Companies will work with the contractor to ascertain the appliances that will be at the premises. This is necessary for the utility to determine the pipe to install, meter size and other information needed to establish service. In many cases, if utility personnel are at a premise, they inspect and note the appliances, which are then updated in the Utilities‟ system. For example, if utility personnel are responding to a gas odor complaint, they will catalog the appliances. These processes help keep the Utilities‟ records current and accurate. Certainly, some customers may be misclassified. However, using appliances as the criterion to determine whether a S.C. No. 1 customer is a heating or non-heating customer and the many methods that the Utilities use to keep track of appliances at each customer location help ensure a high level of accuracy in classifications. *Id*.

Staff witness Johnson opined that the Commission approved the Companies' establishment of residential heating and non-heating classes in Docket No. 12-0511/12-0512 (Cons.). He stated that AG/ELPC witness Rubin does not appear to disagree with the "heating" and "non-heating" sub-classes per se, but rather wants to make sure that the customers are classified correctly as heating or non-heating. The Companies' tariffs specifically designate "Heating Customers" as customers who use gas as their principal source of space heating requirements and "Non-Heating Customers" as customers who do not use gas as their principal source of space heating requirements. (North Shore ILL.C.C.No. 17, Ninth Revised Sheet No. 6 and Peoples Gas ILL.C.C.No. 28, Ninth Revised Sheet No. 5.) Staff has no objection to the Companies' designations for these customers found in the tariffs. (Staff Ex. 9.0, 21.)

However, since the Commission only approved the bifurcation of the residential class into heating and non-heating classes in Docket No. 12-0511/12-0512 (Cons.), dated June 18, 2013, Mr. Johnson understands why AG witness Rubin would want to make sure that customers are classified correctly. Staff witness Johnson stated that he had no objection to the Commission ordering the Companies to do an in-depth study to make sure that "heating" and "non-heating" customers are classified correctly. However, he emphasized that the Commission should also consider that this will probably involve some on-site inspections that will likely include additional costs. Mr. Johnson recommended the Companies provide, in surrebuttal testimony, a rough estimate of the amount of time it would take to carry out such a task and a rough estimate of the likely costs involved. Staff wanted the additional information available so the Commission has a fuller record for making a final determination on this proposal by the AG/ELPC. (*Id*., 21-22.)

Companies' witness Robinson responded in surrebuttal testimony to Staff's recommendation to give a rough estimate of the amount of time it would take to carry out an in-depth study and an estimate of the costs involved. Mr. Robinson stated that subject to the limitations of developing the requested estimates in a short period, the Utilities' rough estimate of the number of accounts that would potentially be inspected is approximately 580,000. This estimate is based on information from the Utilities' customer information system on the number of premises that did not show a physical verification of appliances in the last three years. The Utilities were not able, in the time available, to estimate the costs of further manual review of accounts after the initial query. However, given the large number of accounts, and the need for manual review, physical inspections (possibly including repeat visits when the Utilities could not initially gain access to identify all appliances), or both, it would almost certainly be millions of dollars. (NS-PGL Ex. 46.0, 3-4.)

Mr. Robinson stated that the Utilities do not think a requirement to conduct a study is needed. The Utilities rely on identification of gas appliances to categorize a customer as heating or non-heating. They have long-standing processes, pre-dating the introduction of heating and non-heating rates in S.C. No. 1, to identify the customer's appliances. These processes involve both inquiries when an applicant or customer interacts with a customer service representative or a physical inspection of the premises. The application process alone typically involves tens of thousands of applicants in a year. This means that, at a minimum, the Utilities are verifying appliances for a large percentage of their customer base every year. Because the inquiries focus on appliances and on following up when the applicant's or customer's description of his appliances does not mesh with existing data that the Utilities have about the premises, these existing processes are very effective in correctly categorizing customers. (*Id*., 4.)

Companies witness Robinson proposed an alternative to a study or investigation. He stated that it is his understanding that after a rate case order, the Utilities must communicate with customers about the rate case. They could use that communication to emphasize to S.C. No. 1 customers the significance of the "heating" and "non-heating" designations and encourage customers to call with questions or concerns. (*Id*., 5.)

D. Other Rate Design Issues

1. Terms and Conditions of Service

a. Service Activation

The Companies identify two types of service activations. A succession turn-on occurs when a customer who is moving out of a home or building calls to discontinue gas service at approximately the same time as the applicant moving in calls and requests gas service. In this instance, only one meter reading is taken. A straight turn-on occurs when there has never been gas service at a location, or when the prior customer canceled service before the new applicant calls to request service and the gas has actually been turned off. In this instance, the gas has to be turned on and appliances have to be relit. (NS Ex. 15.0, 20:424-431 and PGL Ex. 15.0, 20-21:434-441.)

North Shore prepared an analysis that identifies the costs associated with a succession turn-on, straight turn-on, and the cost to light an additional appliance over four (Included in any reconnection charge is the relighting of a maximum of four gas appliances per account). (NS Ex. 15.0, 20:431-432.) North Shore's analysis shows that the cost for a succession turn-on is $23.74, the cost of a straight turn-on is $64.07, and the cost to light an additional appliance over four is $16.55. (NS Ex. 15.8) North Shore is proposing that the straight turn-on be increased from $42.00 to $50.00, and the cost for relighting any appliances over four be increased from $10.00 to $12.00. North Shore is proposing to leave the succession turn-on charge at $20.00. (NS Ex. 15.0, 21:435-439.)

PGL prepared an analysis that identifies the costs associated with a succession turn-on, straight turn-on, and the cost to light an additional appliance over four (Included in any reconnection charge is the relighting of a maximum of four gas appliances per account). (NS Ex. 15.0, 21:441-442) PGL's analysis shows that the cost for a succession turn-on is $25.89, the cost of a straight turn-on is $63.42, and the cost to light an additional appliance over four is $17.23. (PGL Ex. 15.8.) PGL is proposing that the succession turn-on be increased from $18.00 to $23.00, the straight turn-on be increased from $30.00 to $38.00, and the cost for relighting any appliances over four be increased from $10.00 to $13.00. (PGL Ex. 15.0, 21:442-448)

Staff witness Johnson has no objection to the Companies' proposals for Service Activation Charges. He stated that they have provided cost break-downs for the various Service Activation Charges and in the interest of gradualism, are not proposing full cost recovery in this proceeding. (Staff Ex. 4.0, 66.)

No other parties addressed this issue.

b. Service Reconnection Charges

A service reconnection charge is applicable to customers, whose gas has been turned off for any number of reasons, including disconnections for non-payment of bills and at the customer's request. However, each customer is granted a waiver of one reconnection charge each year for reconnection at the meter, except in the situation where the customer voluntarily disconnects and then requests reconnection within twelve months. The Companies offer three types of service reconnections following an involuntary disconnection for which the Companies currently charge customers: basic reconnections which only require a meter turn-on, reconnections which require setting a new meter, and reconnections that involve excavating at the main. (NS Ex. 15.0, 21:441-450 and PGL Ex. 15.0, 21:450-459.)

North Shore prepared an analysis that identifies the costs associated with the three service reconnections (basic reconnections, reconnections which require a new meter set, and reconnections that involve excavations at the main). (NS Ex. 15.0, 21:446-450.) North Shore's analysis shows that the cost for a reconnection at the meter (basic reconnection) is $90.72, the cost for a reconnection when the meter has to be reset is $200.46, and the cost for a reconnection at the main is $1,638.63. (NS Ex. 15.8.) North Shore is proposing that the basic reconnection charge remain at $75.00, the cost for reconnection when the meter has to be reset increased from $150.00 to $180.00, and the cost for reconnection at the main increased from $425.00 to $500.00. The Company is also proposing that the charge for relighting each appliance over four will be increased from $10.00 to $12.00, as with the Service Activation Charge. (NS Ex. 15.0, 21-22:455-462.)

PGL also prepared an analysis that identifies the costs associated with the three service reconnections (basic reconnections, reconnections which require a new meter set, and reconnections that involve excavations at the main). (PGL Ex. 15.0, 21:455-459.) PGL's analysis shows that the cost for a reconnection at the meter (basic reconnection) is $112.33, the cost for a reconnection when the meter has to be reset is $439.80, and the cost for a reconnection at the main is $1,338.72. (PGL Ex. 15.8.) PGL is proposing that the basis reconnection charge increase from $75.00 to $94.00, the cost for reconnection when the meter has to be reset increased from $150.00 to $180.00, and the cost for reconnection at the main increased from $425.00 to $500.00. The Company is also proposing that the charge for relighting each appliance over four will be increased from $10.00 to $12.00, as with the Service Activation Charge. (NS Ex. 15.0, 21-22:455-462.)

Staff witness Johnson has no objection to the Companies' proposals for Reconnection Charges. He states that the Companies have provided cost break-downs for the various Service Activation Charges and in the interest of gradualism, are not proposing full cost recovery in this proceeding. (Staff Ex. 4.0, 68.)

No other parties addressed this issue.

c. Second Pulse Data Capability Charge

A customer that has installed an operational meter, meter corrector, or daily demand measurement device capable of providing a second pulse for further data collection capability may choose to have the Companies enable this capability on the meter or device for a monthly charge. (NS Ex. 15.0, 22:464-467 and PGL Ex. 15.0, 22:472-475.)

The Companies provided analyses of the determination of Second Pulse Capability Charges. (NS Ex. 15.12 and PGL Ex. 15.12.) The analysis for North Shore identified that the monthly charge for Second Pulse Data Capability would be $10.25, a decrease from the current charge of $14.00. The analysis for Peoples Gas identified that the monthly charge for Second Pulse Data Capability would be $10.60, a decrease from the current charge of $14.00. *Id*.

Staff witness Johnson stated that he had no objection to the Companies' proposals for Second Pulse Data Capability Charges. However, the Companies have incorporated a rate of return of 7.02% in the calculation of the charge that is based upon the Companies' proposed rate of return. Mr. Johnson recommends the charge be recalculated with the final Commission approved overall rate of return in this proceeding. In response to Staff Data Requests, the Companies stated that they agree that it would be appropriate to update the calculation using the approved overall rate of return set by the Commission in its final Order. (Staff Ex. 4.0, 69.)

No other parties addressed this issue.

2. Riders

a. Rider 5, Gas Service Pipe

b. Rider SSC, Storage Service Charge

The Companies are proposing a change in the per therm charge for the storage service charge resulting from the new revenue requirements proposed in this proceeding. (NS Ex. 15.0, 22 and PGL Ex. 15.0 Rev., 22-23) No party objected to the Companies' proposals.

c. Rider QIP, Qualifying Infrastructure Plant [PGL]

Staff and Peoples Gas agree that language changes to Rider QIP should be made to allow for an adjustment through the Rider QIP surcharge if its 2014 actual additions are different than the amount approved in the instant case. (NS-PGL Ex. 29.0, 24-27; NS-PGL Ex. 29.1; Staff Ex. 6.0, 14) Further, Staff and the Company are in agreement for the need for a findings and ordering paragraph to be included in the Commission's Order concerning Rider QIP. If the Commission's conclusion accepts the AG adjustment to the projected level of 2014 AMRP plant additions recoverable through Rider QIP, the language is as follows:

> Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be

> recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $115,986,348, less a negative amount of $33,721,806 for accumulated depreciation and less a positive amount of $8,603,652 for accumulated deferred income taxes, and $1,728,342 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.
> (NS-PGL Ex.37.5 P, 3-4; NS-PGL Ex. 43.0 REV.)

If the Commission's conclusion rejects the AG adjustment to the projected level of 2014 AMRP plant additions recoverable through Rider QIP and instead accepts Peoples Gas' position, the language is as follows:

> Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $173,237,532, less a negative amount of $58,686,380 for accumulated depreciation and less a positive amount of $16,463,375 for accumulated deferred income taxes, and $2,620,588 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.
> (NS-PGL Ex. 22.14 P; NS-PGL Ex. 43.0 REV.)

d. Rider UEA, Uncollectible Expense Adjustment, and Rider UEA-GC, Uncollectible Expense Adjustment – Gas Costs

e. Rider VBA, Volume Balancing Adjustment, Percentage of Fixed Costs

f. Transportation Riders

i. Transportation Administrative Charges

ii. Rider SBO Credit

iii. Purchase of Receivables

3. Service Classifications

a. S.C. Nos. 1 and 2 Terms of Service

4. Other

X. FINDINGS AND ORDERING PARAGRAPHS

As discussed above, the Order should contain the following findings and ordering paragraphs:

ORIGINAL COST DETERMINATION

> It is further ordered that the $443,539,000 original cost of plant for North Shore at December 31, 2012 and the $3,285,370,000 original cost of plant for Peoples Gas at December 31, 2012, as presented in Staff Exhibit 1.0, are unconditionally approved as the original costs of plant. (NS Ex. 7.0, 14; PGL Ex. 7.0, 17)

RATE CASE EXPENSE (subject to contested amortization period issue)

Based on the amortization period discussed in Section V.C.4, Staff recommends that the Order in this proceeding express a Commission conclusion as follows:

> The Commission has considered the costs expended by the Companies to compensate attorneys and technical experts to prepare and litigate these rate case proceedings and assesses that the total rate case costs for these proceedings of $1,947,000 and $2,945,000 for North Shore and Peoples Gas, respectively, which

are amortized over 2 and a half years and included as rate case expenses in the revenue requirements of $779,000 and $1,178,000 for North Shore and Peoples Gas, respectively, are just and reasonable.

(Staff Ex. 7.0, 16-17.)

PIPELINE SAFETY RELATED TRAINING

The test year amounts of test year pipeline safety-related training for Peoples Gas are: $11,355 for Corrosion-NACE Levels 1 and 2 Certification; $80,500 for Parts 191 and 192 Training; $0 for Construction Inspection; $6,300 for all other pipeline safety-related training, totaling $98,135.

RIDER QIP

(*Adopt AG position*)
Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $115,986,348, less a negative amount of $33,721,806 for accumulated depreciation and less a positive amount of $8,603,652 for accumulated deferred income taxes, and $1,728,342 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.

(*Adopt Peoples Gas position*)
Peoples Gas shall reflect in its Rider QIP Surcharge Percentage following the date of this Order the variance from the 2014 QIP amounts included in base rates to its actual 2014 QIP amounts, which may be an increase or decrease to the amount to be recovered through the Rider QIP Surcharge Percentage. The 2014 QIP amounts included in base rates are comprised of $173,237,532, less a negative amount of $58,686,380 for accumulated depreciation and less a positive amount of $16,463,375 for accumulated deferred income taxes, and $2,620,588 for annualized depreciation expense less annualized depreciation expense applicable to the plant being retired.

LNG TRUCK LOADING FACILITY

> The Commission directs Peoples Gas to file a petition pursuant to Section 7-102 of the PUA (Transactions requiring Commission approval) requesting approval for the construction and operation of a LNG Truck Loading Facility for the solicitation of LNG to non-utility customers prior to Peoples Gas or any of its affiliates initiating the construction of a LNG Truck Loading Facility or entering into contracts to sell LNG by means of the LNG Truck Loading Facility at its Manlove storage field complex.

XI. CONCLUSION

Staff respectfully requests that the Illinois Commerce Commission approve Staff's recommendations in this consolidated docket.

Respectfully submitted,

____

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Counsel for the Staff of the Illinois Commerce Commission

October 21, 2014

North Shore Gas Company
Statement of Operating Income with Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Present (NS-PGL Ex. 21.1 N)	Staff Adjustments (App. A, p. 3)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (NS-PGL Ex. 21.1 N)	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	$ 81,741	$ -	$ 81,741	$ 6,440	$ -	$ 88,181	$ (2,980)	$ 85,201
2	Other Revenues	1,513	-	1,513	84	-	1,597	-	1,597
3	Total Operating Revenue	83,254	-	83,254	6,524	$ -	89,778	(2,980)	86,798
4	Uncollectible Accounts	478	-	478	35	-	513	(16)	497
5	Cost of Gas	-	-	-	-	-	-	-	-
6	Other Production	772	-	772	-	-	772	-	772
7	Storage	-	-	-	-	-	-	-	-
8	Transmission	248	-	248	-	-	248	-	248
9	Distribution	19,455	-	19,455	-	-	19,455	-	19,455
10	Customer Accounts	6,388	-	6,388	-	-	6,388	-	6,388
11	Customer Service and Informational Services	748	-	748	-	-	748	-	748
12	Administrative and General	24,215	(464)	23,751	-	-	23,751	-	23,751
13	Depreciation and Amortization	11,903	-	11,903	-	-	11,903	-	11,903
14	Taxes Other Than Income	3,252	(14)	3,238	-	-	3,238	-	3,238
15	Total Operating Expense								
16	Before Income Taxes	67,459	(478)	66,981	35	-	67,016	(16)	67,000
							-		-
17	State Income Tax	678	43	721	503	-	1,224	(230)	994
18	Federal Income Tax	8,609	184	8,793	2,095	-	10,888	(957)	9,931
19	Deferred Taxes and ITCs Net	(4,744)	-	(4,744)	-	-	(4,744)	-	(4,744)
20	Total Operating Expenses	72,002	(251)	71,751	2,633	-	74,384	(1,203)	73,181
21	NET OPERATING INCOME	$ 11,252	$ 251	$ 11,503	$ 3,891	$ -	$ 15,394	$ (1,777)	$ 13,617
22	Staff Rate Base (App. A, p. 4, Column (d))								$ 218,599
23	Staff Overall Rate of Return (ICC Staff Exhibit 3.0, Schedule 3.01)								6.23%
24	Revenue Change (Col. (i) Line 3 minus Col. (d), Line 3)								$ 3,544
25	Percentage Revenue Change (Col. (i), Line 24 divided by Col. (d), Line 3)								4.26%

North Shore Gas Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Interest Synchronization (App. A, p. 7)	Advertising (Sch. 7.01 N)	Institutional Events (Sch. 7.02 N)	Charitable Contributions (Sch. 7.03 N)	Social & Service Club Dues (Sch. 7.04 N)	Invested Capital Tax (App. A, p. 13)	Rate Case Expense (Sch. 7.06 N)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Cost of Gas	-	-	-	-	-	-	-	-
6	Other Production	-	-	-	-	-	-	-	-
7	Storage	-	-	-	-	-	-	-	-
8	Transmission	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-
10	Customer Accounts	-	-	-	-	-	-	-	-
11	Customer Service and Informational Se	-	-	-	-	-	-	-	-
12	Administrative and General	-	(4)	(10)	(1)	(17)	-	(260)	(292)
13	Depreciation and Amortization	-	-	-	-	-	-	-	-
14	Taxes Other Than Income	-	-	-	-	-	(14)	-	(14)
15	Total Operating Expense								
16	Before Income Taxes	-	(4)	(10)	(1)	(17)	(14)	(260)	(306)
								-	
17	State Income Tax	7	-	1	-	1	1	20	30
18	Federal Income Tax	30	1	3	-	5	5	84	128
19	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
20	Total Operating Expenses	37	(3)	(6)	(1)	(11)	(8)	(156)	(148)
21	NET OPERATING INCOME	$ (37)	$ 3	$ 6	$ 1	$ 11	$ 8	$ 156	$ 148

North Shore Gas Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	(App. A, p. 2)	Legal Expenses (AG Ex. 1.1, p. 7)	(Source)	(Source)	(Source)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Cost of Gas	-	-	-	-	-	-	-	-
6	Other Production	-	-	-	-	-	-	-	-
7	Storage	-	-	-	-	-	-	-	-
8	Transmission	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-
10	Customer Accounts	-	-	-	-	-	-	-	-
11	Customer Service and Informational Se	-	-	-	-	-	-	-	-
12	Administrative and General	(292)	(172)	-	-	-	-	-	(464)
13	Depreciation and Amortization	-	-	-	-	-	-	-	-
14	Taxes Other Than Income	(14)	-	-	-	-	-	-	(14)
15	Total Operating Expense								
16	Before Income Taxes	(306)	(172)	-	-	-	-	-	(478)
17	State Income Tax	30	13	-	-	-	-	-	43
18	Federal Income Tax	128	56	-	-	-	-	-	184
19	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
20	Total Operating Expenses	(148)	(103)	-	-	-	-	-	(251)
21	NET OPERATING INCOME	$ 148	$ 103	$ -	$ -	$ -	$ -	$ -	$ 251

North Shore Gas Company
Rate Base
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Company Rebuttal Pro Forma Rate Base (NS-PGL Ex. 22.1 N)	Staff Adjustments (App. A, p. 5)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Utility Plant	$ 501,529	$ -	$ 501,529
2	Accumulated Provision for Depr. & Amort.	(200,691)	-	(200,691)
3	-	-	-	-
4	Net Plant	300,838	-	300,838
5	Additions to Rate Base			
6	Cash Working Capital	(1,721)	(744)	(2,465)
7	Materials and Supplies	1,928	-	1,928
8	Gas in Storage	6,238	-	6,238
9	Retirement Benefits, Net	(4,963)	(749)	(5,712)
10	Budget Plan Balances	831	-	831
11	-	-	-	-
12	-	-	-	-
13	-	-	-	-
14	-	-	-	-
15	-	-	-	-
16	Deductions From Rate Base			
17	Accumulated Deferred Income Taxes	(79,725)	306	(79,419)
18	Customer Deposits	(1,996)	-	(1,996)
19	Customer Advances for Construction	(562)	-	(562)
20	Reserve for Injuries and Damages	(1,082)	-	(1,082)
21	-	-	-	-
22	-	-	-	-
23	Rate Base	$ 219,786	$ (1,187)	$ 218,599

North Shore Gas Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Cash Working Capital (App. A, p. 9)	Pension Asset (Sch. 6.09 N)	(Source)	(Source)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Utility Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Accumulated Provision for Depr. & Amort.	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-
4	Net Plant	-	-	-	-	-	-	-	-
	-								
5	Additions to Rate Base								-
6	Cash Working Capital	(744)	-	-	-	-	-	-	(744)
7	Materials and Supplies	-	-	-	-	-	-	-	-
8	Gas in Storage	-	-	-	-	-	-	-	-
9	Retirement Benefits, Net	-	(749)	-	-	-	-	-	(749)
10	Budget Plan Balances	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Accumulated Deferred Income Taxes	-	306	-	-	-	-	-	306
18	Customer Deposits	-	-	-	-	-	-	-	-
19	Customer Advances for Construction	-	-	-	-	-	-	-	-
20	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-
21	Deferred State Income Taxes	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
	-								
23	Rate Base	$ (744)	$ (443)	$ -	$ -	$ -	$ -	$ -	$ (1,187)

North Shore Gas Company
Revenue Effect of Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Per Company	Staff Adjustments	Per Staff
	(a)	(b)	(c)	(d)
1	Present Revenues	$ 83,254 [1]	$ -	$ 83,254 [2]
2	Proposed Increase	6,524 [3]	(2,980) [4]	3,544 [5]
3	Proposed Revenues	$ 89,778	$ (2,980)	$ 86,798
4	% Increase	7.84%		4.26%
5	Staff Adjustments:			
6	Rate of Return (Applied to Company Rate Base)		(2,435)	
7	Rate Case Expense		(262)	
8	Legal Expenses		(173)	
9	Cash Working Capital		(69)	
10	Pension Asset		(41)	
11	Social & Service Club Dues		(18)	
12	Invested Capital Tax		(13)	
13	Institutional Events		(10)	
14	Advertising Expense		(5)	
15	Charitable Contributions		(2)	
16	Interest Synchronization		49	
17				
18				
19				
20				
21				
22				
23				
24	Rounding		(1)	
25	Total Revenue Effect of Staff Adjustments		$ (2,980)	

Sources:
(1) App. A, p. 1, column (b), line 3
(2) App. A, p. 1, column (d), line 3
(3) App. A, p. 1, column (e), line 3
(4) App. A, p. 1, columns (f) + (h), line 3
(5) App. A, p. 1, column (i), line 24

North Shore Gas Company
Interest Synchronization Adjustment
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Rate Base	$ 218,599	(1)
2	Weighted Cost of Debt	1.69%	(2)
3	Synchronized Interest Per Staff	3,686	
4	Company Interest Expense	3,780	(3)
5	Increase (Decrease) in Interest Expense	(94)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.750%	$ 7	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 30	

(1) Source: App. A, p. 4, Column (d).
(2) Source: ICC Staff Exhibit 6.0, Schedule 3.01.
(3) Source: NS-PGL Ex. 21.2 N, p. 5

North Shore Gas Company
Gross Revenue Conversion Factor
For the Test Year Ending December 31, 2015

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	
2	Uncollectibles	0.5403%	0.005403	
3	State Taxable Income		0.994597	1.000000
4	State Income Tax	7.7500%	0.077081	0.077500
5	Federal Taxable Income		0.917516	0.922500
6	Federal Income Tax	35.0000%	0.321131	0.322875
7	Operating Income		0.596385	0.599625
8	Gross Revenue Conversion Factor Per Staff		1.676769	1.667709

North Shore Gas Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No. (A)	Item (B)	Amount (C)	Lag (Lead) (D)	CWC Factor (D) / 365 (E) (D/365)	CWC Requirement (C) x (E) (F)	Column (C) Source (G)
1	Revenues	$ 174,139	36.86	0.10099	$ 17,586	App. A, p. 10, line 7
2	ICC Gas Revenue Tax	$ 205	36.86	0.10099	$ 21	Line 23 Below
3	Other Pass Through Taxes	15,836	0.00	0.00000	-	Sum of lines 23 - 27 below
4	Total	$ 190,180			$ 17,607	Line 1 + line 2 +lLine 3
5	Payroll and Withholdings	$ 11,466	(14.02)	(0.03841)	(440)	NS-PGL Ex. 22.1 N, p. 1, line 8
6	Incentive Pay	288	(249.50)	(0.68356)	(197)	NS-PGL Ex. 22.1 N, p. 2, line 13
7	Inter Company Billings	30,348	(34.90)	(0.09562)	(2,902)	NS-PGL Ex. 22.1 N, p. 1, line 10
8	Natural Gas	104,928	(40.35)	(0.11055)	(11,600)	App. A, p. 10, line 2
9	Pension	2,383	(34.90)	(0.09562)	(228)	NS-PGL Ex. 22.1 N, p. 1, line 12
10	OPEB	1,189	(170.00)	(0.46575)	(554)	App. A, p. 12, line 8, col (R) * -1
11	Other Benefits	2,428	(47.78)	(0.13090)	(318)	NS-PGL Ex. 22.1 N, p. 1, line 14
12	Other Operations and Maintenance	3,855	(46.90)	(0.12849)	(495)	App. A, p. 10, line 20
13	Federal Insurance Contributions (FICA)	759	(16.16)	(0.04427)	(34)	NS-PGL Ex. 22.1 N, p. 1, line 17
14	Federal Unemployment Tax	4	(76.38)	(0.20926)	(1)	NS-PGL Ex. 22.1 N, p. 1, line 18
15	State Unemployment Tax	19	(73.25)	(0.20068)	(4)	NS-PGL Ex. 22.1 N, p. 1, line 19
16	Property/Real Estate Taxes	272	(379.37)	(1.03937)	(283)	NS-PGL Ex. 22.1 N, p. 1, line 20
17	Invested Capital Tax	1,486	(31.13)	(0.08529)	(127)	App. A, p. 11, line 6
18	Corporation Franchise Tax	26	(173.37)	(0.47499)	(12)	NS-PGL Ex. 22.1 N, p. 1, line 22
19	Illinois Sales and Use Tax	53	(44.04)	(0.12066)	(6)	NS-PGL Ex. 22.1 N, p. 1, line 23
20	Federal Excise Tax	3	(76.62)	(0.20992)	(1)	NS-PGL Ex. 22.1 N, p. 1, line 24
21		-	0.00	0.00000	-	
22	Unauthorized Insurance Tax	21	166.96	0.45742	10	NS-PGL Ex. 22.1 N, p. 1, line 25
23	ICC Gas Revenue Tax	205	27.15	0.07438	15	NS-PGL Ex. 22.1 N, p. 1, line 27
24	Gross Receipts/Municipal Utility Tax	6,213	(58.05)	(0.15904)	(988)	NS-PGL Ex. 22.1 N, p. 1, line 28
25	Energy Assistance Charges	1,792	(23.08)	(0.06323)	(113)	NS-PGL Ex. 22.1 N, p. 1, line 29
26	IDOR Gas Revenue/Public Utility Tax	7,831	6.70	0.01836	144	NS-PGL Ex. 22.1 N, p. 1, line 30
27				0.00000	-	
28	Interest Expense	3,686	(79.31)	(0.21729)	(801)	App. A, p. 7, line 3
29	Federal Income Tax	9,931	(38.00)	(0.10411)	(1,034)	App. A, p. 1, col. (i), line 18
30	State Income Tax	994	(38.00)	(0.10411)	(103)	App. A, p. 1, col. (i), line 19
31	Total	$ 190,180			$ (20,072)	Sum of lines 5 through 30
32	Cash Working Capital per Staff				$ (2,465)	Line 4 + line 31
33	Cash Working Capital per Company				(1,721)	NS-PGL Ex. 22.1 N, p. 1, line 34
34	Difference -- Adjustment				$ (744)	Line 32 - line 33

Note: Lag (Lead) is from NS-PGL Ex. 22.13 N, p. 1

North Shore Gas Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No. (A)	Description (B)	Amount (C)	Source (D)
1	Total Operating Revenues	$ 86,798	App. A, p. 1, col. (i), line 3
2	PGA Revenue	104,928	NS-PGL Ex. 22.1 N, p. 2, line 2
3	Uncollectible Accounts	(497)	App. A, p. 1, col. (i), line 4
4	Depreciation & Amortization	(11,903)	App. A, p. 1, col. (i), line 13
5	Deferred Taxes and ITCs Net	4,744	App. A, p. 1, col. (i), line 19
6	Return on Common Equity	(9,931)	Line 10 below
7	Total Revenues for CWC calculation	$ 174,139	Sum of lines 1 through 6
8	Total Rate Base	$ 218,599	App. A, p. 4, col. (d), line 23
9	Weighted Cost of Common Equity	4.54%	Staff Ex. 8.0
10	Return on equity deduction from revenue	$ 9,931	Line 8 x Line 9
11	Other O & M Expenses	$ 51,859	App. A, p. 1, col. (i), sum of lines 4 through 12
12	Payroll and Withholdings	(11,466)	NS-PGL Ex. 22.1 N, p. 2, line 12
13	Incentive Pay	(288)	NS-PGL Ex. 22.1 N, p. 2, line 13
14	Inter-Company Billings	(30,348)	NS-PGL Ex. 22.1 N, p. 2, line 35
15	Pension	(2,383)	NS-PGL Ex. 22.1 N, p. 2, line 27 + line 28
16	OPEB	(1,189)	NS-PGL Ex. 22.1 N, p. 2, line 29 + line 30
17	Other Benefits	(2,428)	NS-PGL Ex. 22.1 N, p. 2, line 31
18	Payroll Taxes in Account 408	595	NS-PGL Ex. 22.1 N, p. 2, line 32
19	Uncollectible Accounts	(497)	App. A, p. 1, col. (i), line 4
20			
21	Other Operations & Maintenance (net)	$ 3,855	Sum of lines 11 through 20

North Shore Gas Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No. (A)	Description (B)	Amount (C)	Source (D)
1	Invested Capital Tax per Company Filing	$ 1,500	NS-PGL Ex. 22.1 N, p. 1, line 21
2	Invested Capital Tax Adjustment	(14)	App. A, p. 13, line 9
3	Invested Capital Tax per Order	$ 1,486	Sum of lines 1 and 2

North Shore Gas Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2015
OPEB Lead Calculation

Line No.	Invoice	Invoice Descr	Amount	Invoice Date	Voucher ID	Year	Period	Unit	Journal Date	Service Begin	Service End	Service Lead	Payment Date	Payment Lead	Total Lead	Weighting	Weighted Lead
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
1	2012VEBACONT-B	CONTRIB TO PE INSUR	7,500,000.00	2012-01-04	00000143	2012	1	1200	2012-01-09	1/1/2012	12/31/2012	183.00	**12/18/2012**	(13.00)	170.00	0.6879	116.9466
2																	
3	2012PEVEBACONT3	INS CONTRIB	368,676.00	2012-12-13	00000313	2012	12	1200	2012-12-18	1/1/2012	12/31/2012	183.00	2012-12-18	(13.00)	170.00	0.0338	5.7487
4	2012PEVEBACONT1	GROUP INSURANCE	2,992,120.00	2012-12-13	00000314	2012	12	1200	2012-12-18	1/1/2012	12/31/2012	183.00	2012-12-18	(13.00)	170.00	0.2744	46.6558
5	2012PEVEBACONT2	CONTRIB TO INS PLAN	41,616.00	2012-12-13	00000315	2012	12	1200	2012-12-18	1/1/2012	12/31/2012	183.00	2012-12-18	(13.00)	170.00	0.0038	0.6489
6																	
7																	
8			10,902,412.00													1.0000	170.00

North Shore Gas Company
Adjustment For Invested Capital Taxes
For the Test Year Ending December 31, 2015
(In Thousands)

Line (A)	Description (B)	Amount (C)	Source (D)
1	Rate Base	$ 218,599	App. A, p. 1, col. i, line 22
2	Rate of Return	6.23%	App. A, p. 1, col. i, line 23
3	Operating Income Required	$ 13,617	Line 1 x Line 2
4	Pro forma operating income at present rates adjusted before ICT adjustment	11,517	App. A, p. 1, col. (d) line 21 - App. A, p. 2, col. (g) line 14
5	Operating Income Additional Allowed	$ 2,100	Line 3 - line 4
6	Invested Capital Tax Rate	0.80%	NS Schedule WPC-2.13
7	Incremental Invested Capital Tax Impact per Staff	$ 17	Line 5 x line 6
8	Incremental Invested Capital Tax Impact per Company	31	NS PGL Ex.21.2N. p. 4
9	Adjustment	$ (14)	Line 7 - line 8

The Peoples Gas Light and Coke Company
Statement of Operating Income with Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Company Surrebuttal Pro Forma Present (NS-PGL Ex. 36.1 P)	Staff Adjustments (App. B, p. 3)	Staff Pro Forma Present (Cols. b+c)	Company Rebuttal Proposed Increase (NS-PGL Ex. 36.1 P)	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	$ 581,934	$ -	$ 581,934	$ 98,867	$ -	$ 680,801	$ (29,462)	$ 651,339
2	Other Revenues	14,932	-	14,932	1,674	-	16,606	-	16,606
3	Total Operating Revenue	596,866	-	596,866	100,541	$ -	697,407	(29,462)	667,945
4	Uncollectible Accounts	12,176	-	12,176	2,039	-	14,215	(598)	13,617
5	Cost of Gas	-	-	-	-	-	-	-	-
6	Other Production	1,472	-	1,472	-	-	1,472	-	1,472
7	Storage	11,427	-	11,427	-	-	11,427	-	11,427
8	Transmission	6,188	-	6,188	-	-	6,188	-	6,188
9	Distribution	165,347	-	165,347	-	-	165,347	-	165,347
10	Customer Accounts	31,505	-	31,505	-	-	31,505	-	31,505
11	Customer Service and Informational Services	2,637	-	2,637	-	-	2,637	-	2,637
12	Administrative and General	138,282	(719)	137,563	-	-	137,563	-	137,563
13	Depreciation and Amortization	112,762	(1,178)	111,584	-	-	111,584	-	111,584
14	Taxes Other Than Income	25,694	(140)	25,554	-	-	25,554	-	25,554
15	Total Operating Expense								
16	Before Income Taxes	507,490	(2,037)	505,453	2,039	-	507,492	(598)	506,894
							-		-
17	State Income Tax	2,280	285	2,565	7,634	-	10,199	(2,237)	7,962
18	Federal Income Tax	32,941	1,189	34,130	31,804	-	65,934	(9,319)	56,615
19	Deferred Taxes and ITCs Net	(13,627)	-	(13,627)	-	-	(13,627)	-	(13,627)
20	Total Operating Expenses	529,084	(563)	528,521	41,477	-	569,998	(12,154)	557,844
21	NET OPERATING INCOME	$ 67,782	$ 563	$ 68,345	$ 59,064	$ -	$ 127,409	$ (17,308)	$ 110,101
22	Staff Rate Base (App. B, p. 4, Column (d))								$ 1,670,732
23	Staff Overall Rate of Return (ICC Staff Exhibit 3.0, Schedule 3.01)								6.59%
24	Revenue Change (Col. (i) Line 3 minus Col. (d), Line 3)								$ 71,079
25	Percentage Revenue Change (Col. (i), Line 24 divided by Col. (d), Line 3)								11.91%

The Peoples Gas Light and Coke Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Interest Synchronization (App. B, p. 7)	Advertising (Sch. 7.01 P)	Institutional Events (Sch. 7.02 P)	Charitable Contributions (Sch. 7.03 P)	Social & Service Club Dues (Sch. 7.04 P)	Invested Capital Tax (App. B, p. 13)	Rate Case Expense (Sch. 7.06 P)	Subtotal Operating Statement Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Cost of Gas	-	-	-	-	-	-	-	-
6	Other Production	-	-	-	-	-	-	-	-
7	Storage	-	-	-	-	-	-	-	-
8	Transmission	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-
10	Customer Accounts	-	-	-	-	-	-	-	-
11	Customer Service and Informational Se	-	-	-	-	-	-	-	-
12	Administrative and General	-	(51)	(203)	(28)	(44)	-	(393)	(719)
13	Depreciation and Amortization	-	-	-	-	-	-	-	-
14	Taxes Other Than Income	-	-	-	-	-	(140)	-	(140)
15	Total Operating Expense								
16	Before Income Taxes	-	(51)	(203)	(28)	(44)	(140)	(393)	(859)
								-	
17	State Income Tax	128	4	16	2	3	11	30	194
18	Federal Income Tax	532	16	66	9	14	45	127	809
19	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
20	Total Operating Expenses	660	(31)	(121)	(17)	(27)	(84)	(236)	144
21	NET OPERATING INCOME	$ (660)	$ 31	$ 121	$ 17	$ 27	$ 84	$ 236	$ (144)

The Peoples Gas Light and Coke Company
Adjustments to Operating Income
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	(App. B, p. 2)	2014 Rider QIP Additions (AG Ex. 7.0; NS-PGL Ex. 37.5 P)	(Source)	(Source)	(Source)	(Source)	(Source)	Total Operating Statement Adjustments
	(a)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Base Rate Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Other Revenues	-	-	-	-	-	-	-	-
3	Total Operating Revenue	-	-	-	-	-	-	-	-
4	Uncollectible Accounts	-	-	-	-	-	-	-	-
5	Cost of Gas	-	-	-	-	-	-	-	-
6	Other Production	-	-	-	-	-	-	-	-
7	Storage	-	-	-	-	-	-	-	-
8	Transmission	-	-	-	-	-	-	-	-
9	Distribution	-	-	-	-	-	-	-	-
10	Customer Accounts	-	-	-	-	-	-	-	-
11	Customer Service and Informational Services	-	-	-	-	-	-	-	-
12	Administrative and General	(719)	-	-	-	-	-	-	(719)
13	Depreciation and Amortization	-	(1,178)	-	-	-	-	-	(1,178)
14	Taxes Other Than Income	(140)	-	-	-	-	-	-	(140)
15	Total Operating Expense								
16	Before Income Taxes	(859)	(1,178)	-	-	-	-	-	(2,037)
17	State Income Tax	194	91	-	-	-	-	-	285
18	Federal Income Tax	809	380	-	-	-	-	-	1,189
19	Deferred Taxes and ITCs Net	-	-	-	-	-	-	-	-
20	Total Operating Expenses	144	(707)	-	-	-	-	-	(563)
21	NET OPERATING INCOME	$ (144)	$ 707	$ -	$ -	$ -	$ -	$ -	$ 563

The Peoples Gas Light and Coke Company
Rate Base
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Company Surrebuttal Pro Forma Rate Base (NS-PGL Ex. 37.1 P)	Staff Adjustments (App. B, p. 5)	Staff Pro Forma Rate Base (Col. b+c)
	(a)	(b)	(c)	(d)
1	Gross Utility Plant	$ 3,482,659	$ (57,251)	$ 3,425,408
2	Accumulated Provision for Depr. & Amort.	(1,245,048)	(24,091)	(1,269,139)
3	-	-	-	-
4	Net Plant	2,237,611	(81,342)	2,156,269
5	Additions to Rate Base			
6	Cash Working Capital	10,783	(4,710)	6,073
7	Materials and Supplies	15,302	-	15,302
8	Gas in Storage	47,405	-	47,405
9	Retirement Benefits, Net	(8,916)	(17,350)	(26,266)
10	Budget Plan Balances	10,847	-	10,847
11	-	-	-	-
12	-	-	-	-
13	-	-	-	-
14	-	-	-	-
15	-	-	-	-
16	Deductions From Rate Base			
17	Accumulated Deferred Income Taxes	(520,978)	14,845	(506,133)
18	Customer Deposits	(23,657)	-	(23,657)
19	Customer Advances for Construction	(1,494)	-	(1,494)
20	Reserve for Injuries and Damages	(7,614)	-	(7,614)
21	-	-	-	-
22	-	-	-	-
23	Rate Base	$ 1,759,289	$ (88,557)	$ 1,670,732

The Peoples Gas Light and Coke Company
Adjustments to Rate Base
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Cash Working Capital (App. B, p. 9)	Pension Asset (Sch. 6.09 P)	2014 Rider QIP Additions (AG Ex. 7.0; NS-PGL Ex. 37.5 P)	(Source)	(Source)	(Source)	(Source)	Total Rate Base Adjustments
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gross Utility Plant	$ -	$ -	$ (57,251)	$ -	$ -	$ -	$ -	$ (57,251)
2	Accumulated Provision for Depr. & Amort.	-	-	(24,091)	-	-	-	-	(24,091)
3	-	-	-	-	-	-	-	-	-
4	Net Plant	-	-	(81,342)	-	-	-	-	(81,342)
	-								
5	Additions to Rate Base								-
6	Cash Working Capital	(4,710)	-	-	-	-	-	-	(4,710)
7	Materials and Supplies	-	-	-	-	-	-	-	-
8	Gas in Storage	-	-	-	-	-	-	-	-
9	Retirement Benefits, Net	-	(17,350)	-	-	-	-	-	(17,350)
10	Budget Plan Balances	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-
16	Deductions From Rate Base	-	-	-	-	-	-	-	-
17	Accumulated Deferred Income Taxes	-	6,881	7,964	-	-	-	-	14,845
18	Customer Deposits	-	-	-	-	-	-	-	-
19	Customer Advances for Construction	-	-	-	-	-	-	-	-
20	Deferred Federal Income Taxes	-	-	-	-	-	-	-	-
21	Deferred State Income Taxes	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-
	-								
23	Rate Base	$ (4,710)	$ (10,469)	$ (73,378)	$ -	$ -	$ -	$ -	$ (88,557)

The Peoples Gas Light and Coke Company
Revenue Effect of Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description (a)	Per Company (b)	Staff Adjustments (c)	Per Staff (d)
1	Present Revenues	$ 596,866 (1)	$ -	$ 596,866 (2)
2	Proposed Increase	100,541 (3)	(29,462) (4)	71,079 (5)
3	Proposed Revenues	$ 697,407	$ (29,462)	$ 667,945
4	% Increase	16.84%		11.91%
5	Staff Adjustments:			
6	Rate of Return (Applied to Company Rate Base)		(18,570)	
7	2014 Rider QIP Additions		(8,403)	
8	Pension Asset		(1,027)	
9	Cash Working Capital		(462)	
10	Rate Case Expense		(402)	
11	Institutional Events		(206)	
12	Invested Capital Tax		(143)	
13	Interest Synchronization		(122)	
14	Advertising Expense		(53)	
15	Social & Service Club Dues		(46)	
16	Charitable Contributions		(29)	
17				
18				
19				
20				
21				
22				
23				
24				
25				
26	Rounding		1	
27	Total Revenue Effect of Staff Adjustments		$ (29,462)	

Sources:
(1) Appendix B, p. 1, column (b), line 3
(2) Appendix B, p. 1, column (d), line 3
(3) Appendix B, p. 1, column (e), line 3
(4) Appendix B, p. 1, columns (f) + (h), line 3
(5) Appendix B, p. 1, column (i), line 24

The Peoples Gas Light and Coke Company
Interest Synchronization Adjustment
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Amount	
	(a)	(b)	
1	Rate Base	$ 1,670,732	(1)
2	Weighted Cost of Debt	2.06%	(2)
3	Synchronized Interest Per Staff	34,417	
4	Company Interest Expense	36,065	(3)
5	Increase (Decrease) in Interest Expense	(1,648)	
6	Increase (Decrease) in State Income Tax Expense		
7	at 7.750%	$ 128	
8	Increase (Decrease) in Federal Income Tax Expense		
9	at 35.000%	$ 532	

(1) Source: App. B, p. 4, Column (d).
(2) Source: ICC Staff Exhibit 3.0, Schedule 3.01.
(3) Source: NS-PGL Ex. 36.2 P, p. 3

The Peoples Gas Light and Coke Company
Gross Revenue Conversion Factor
For the Test Year Ending December 31, 2015

Line No.	Description	Rate	Per Staff With Bad Debts	Per Staff Without Bad Debts
	(a)	(b)	(c)	(d)
1	Revenues		1.000000	
2	Uncollectibles	2.0281%	0.020281	
3	State Taxable Income		0.979719	1.000000
4	State Income Tax	7.7500%	0.075928	0.077500
5	Federal Taxable Income		0.903791	0.922500
6	Federal Income Tax	35.0000%	0.316327	0.322875
7	Operating Income		0.587464	0.599625
8	Gross Revenue Conversion Factor Per Staff		1.702232	1.667709

The Peoples Gas Light and Coke Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Item	Amount	Lag (Lead)	CWC Factor (D) / 365	CWC Requirement (C) x (E)	Column (C) Source
(A)	(B)	(C)	(D)	(E) (D/365)	(F)	(G)
1	Revenues	$ 931,333	46.16	0.12647	$ 117,782	App. B, p. 10, line 7
2	ICC Gas Revenue Tax	$ 1,093	46.16	0.12647	$ 138	Line 23 Below
3	Other Pass Through Taxes	163,878	0.00	0.00000	-	Sum of lines 23 - 27 below
4	Total	$ 1,096,296			$ 117,920	Line 1 + line 2 +line 3
5	Payroll and Withholdings	$ 77,212	(14.26)	(0.03907)	(3,017)	NS-PGL Ex. 37.4 P, p. 1, line 9
6	Incentive Pay	1,879	(249.50)	(0.68356)	(1,284)	NS-PGL Ex. 37.4 P, p. 2, line 13
7	Inter Company Billings	175,458	(35.24)	(0.09655)	(16,940)	NS-PGL Ex. 37.4 P, p. 1, line 11
8	Natural Gas	450,646	(40.56)	(0.11112)	(50,077)	App. B, p. 10, line 2
9	Pension	21,662	(35.24)	(0.09655)	(2,091)	NS-PGL Ex. 37.4 P, p. 1, line 13
10	OPEB	6,448	(169.91)	(0.46550)	(3,002)	App. B, p. 12, line 19, col (R) * -1
11	Other Benefits	15,452	(52.72)	(0.14444)	(2,232)	NS-PGL Ex. 37.4 P, p. 1, line 15
12	Other Operations and Maintenance	61,599	(46.70)	(0.12795)	(7,881)	App. B, p. 10, line 20
13	Federal Insurance Contributions (FICA)	5,084	(16.25)	(0.04452)	(226)	NS-PGL Ex. 37.4 P, p. 1, line 18
14	Federal Unemployment Tax	13	(76.38)	(0.20926)	(3)	NS-PGL Ex. 37.4 P, p. 1, line 19
15	State Unemployment Tax	99	(73.43)	(0.20118)	(20)	NS-PGL Ex. 37.4 P, p. 1, line 20
16	Property/Real Estate Taxes	1,089	(304.74)	(0.83490)	(909)	NS-PGL Ex. 37.4 P, p. 1, line 21
17	Invested Capital Tax	15,058	(35.17)	(0.09636)	(1,451)	App. B, p. 11, line 6
18	Corporation Franchise Tax	220	(176.55)	(0.48370)	(106)	NS-PGL Ex. 37.4 P, p. 1, line 23
19	Sales, Use and Accelerated Tax	227	(7.23)	(0.01981)	(4)	NS-PGL Ex. 37.4 P, p. 1, line 24
20	Federal Excise Tax	32	(76.20)	(0.20877)	(7)	NS-PGL Ex. 37.4 P, p. 1, line 25
21	Chicago Employer's Expense Tax	-	0.00	0.00000	-	
22	Unauthorized Insurance Tax	153	148.37	0.40649	62	NS-PGL Ex. 37.4 P, p. 1, line 27
23	ICC Gas Revenue Tax	1,093	32.79	0.08984	98	NS-PGL Ex. 37.4 P, p. 1, line 29
24	Gross Receipts/Municipal Utility Tax	87,235	(26.51)	(0.07263)	(6,336)	NS-PGL Ex. 37.4 P, p. 1, line 30
25	Energy Assistance Charges	9,690	(21.71)	(0.05948)	(576)	NS-PGL Ex. 37.4 P, p. 1, line 31
26	IDOR Gas Revenue/Public Utility Tax	36,412	7.65	0.02096	763	NS-PGL Ex. 37.4 P, p. 1, line 32
27	City of Chicago Gas Use tax	30,541	(26.52)	(0.07266)	(2,219)	NS-PGL Ex. 37.4 P, p. 1, line 33
28	Interest Expense	34,417	(82.42)	(0.22581)	(7,772)	App. B, p. 7, line 3
29	Federal Income Tax	56,615	(38.00)	(0.10411)	(5,894)	App. B, p. 1, col. (i), line 18
30	State Income Tax	7,962	(38.00)	(0.10411)	(829)	App. B, p. 1, col. (i), line 19
31	Total	$ 1,096,296			$ (111,953)	Sum of lines 5 through 30
32	Cash Working Capital per Staff				$ 5,967	Line 4 + line 31
33	Cash Working Capital per Company				10,677	NS-PGL Ex. 37.4 P, p. 1, line 37
34	Difference -- Adjustment				$ (4,710)	Line 32 - line 33

Note: Lag (Lead) is from NS-PGL Ex. 37.4 P, p. 1

The Peoples Gas Light and Coke Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No. (A)	Description (B)	Amount (C)	Source (D)
1	Total Operating Revenues	$ 667,945	App. B, p. 1, col. (i), line 3
2	PGA Revenue	450,646	NS-PGL Ex. 37.4 P, p. 2, Line 2
3	Uncollectible Accounts	(13,617)	App. B, p. 1, col. (i), line 4
4	Depreciation & Amortization	(111,584)	App. B, p. 1, col. (i), line 13
5	Deferred Taxes and ITCs Net	13,627	App. B, p. 1, col. (i), line 19
6	Return on Common Equity	(75,684)	Line 10 below
7	Total Revenues for CWC calculation	$ 931,333	Sum of Lines 1 through 6
8	Total Rate Base	$ 1,670,732	App. B, p. 4, col. (d), line 23
9	Weighted Cost of Common Equity	4.53%	Staff Ex. 8.0
10	Return on equity deduction from revenue	$ 75,684	Line 8 x line 9
11	Other O & M Expenses	$ 369,756	App. B, p. 1, col. (i), sum of lines 4 through 12
12	Payroll and Withholdings	(77,212)	NS-PGL Ex. 37.43 P, p. 2, Line 12
13	Incentive Pay	(1,879)	NS-PGL Ex. 37.4 P, p. 2, line 13
14	Inter-Company Billings	(175,458)	NS-PGL Ex. 37.4 P, p. 2, Line 40
15	Pension	(21,662)	NS-PGL Ex. 37.4 P, p. 2, Line 32 + line 33
16	OPEB	(6,448)	NS-PGL Ex. 37.4 P, p. 2, Line 34 + line 35
17	Other Benefits	(15,452)	NS-PGL Ex. 37.4 P, p. 2, Line 36
18	Payroll Taxes in Account 408	3,571	NS-PGL Ex. 37.4 P, p. 2, Line 38
19	Uncollectible Accounts	(13,617)	App. B, p. 1, col. (i), line 4
20			
21	Other Operations & Maintenance (net)	$ 61,599	Sum of lines 11 through 20

The Peoples Gas Light and Coke Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2015
(In Thousands)

Line No.	Description	Amount	Source
(A)	(B)	(C)	(D)
1	Invested Capital Tax per Company Filing	$ 15,198	NS-PGL Ex. 37.4 P, p. 1, line 22
2	Invested Capital Tax Adjustment	(140)	App. B, p. 13
3	Invested Capital Tax per Order	$ 15,058	Sum of lines 1 and 2

The Peoples Gas Light and Coke Company
Cash Working Capital Adjustments
For the Test Year Ending December 31, 2015
OPEB Lead Calculation

Line No.	Invoice	Invoice Descr	Amount	Invoice Date	Voucher ID	Year	Period	Unit	Journal Date	Service Begin	Service End	Service Lead	Payment Date	Payment Lead	Total Lead	Weighting	Weighted Lead
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
1	2012VEBACONT-B	CONTRIB TO PE INSUR	67,500,000.00	2012-01-04	00000143	2012	1	1100	2012-01-09	1/1/2012	12/31/2012	183.00	**12/18/2012**	(13.00)	170.00	0.781961	132.93345
2																	
3																	
4																	
5	MHANNON	REIMBURSE HEALTHCARE	10,402.00	2012-01-17	00109062	2012	1	1100	2012-01-17	1/1/2012	1/31/2012	15.50	2012-01-17	(14.00)	1.50	0.000121	0.00018
6	MHANNON1	REIMBURSE HEALTHCARE ACCT	8,278.00	2012-02-09	00110246	2012	2	1100	2012-02-10	2/1/2012	2/29/2012	14.50	2012-02-10	(19.00)	(4.50)	0.000096	(0.00043)
7	MHANNON-2000	REIMBURSE HEALTHCARE	674.00	2012-05-16	00115252	2012	5	1100	2012-05-17	5/1/2012	5/31/2012	15.50	2012-05-17	(14.00)	1.50	0.000008	0.00001
8	MHANNON1	REIMBURSE HEALTH CARE ACCT	1,811.00	2012-06-25	00117149	2012	6	1100	2012-06-25	6/1/2012	6/30/2012	15.00	2012-06-25	(5.00)	10.00	0.000021	0.00021
9	MHANNON	Reimburse Health Care Acct	4,790.00	2012-07-12	00118096	2012	7	1100	2012-07-12	7/1/2012	7/31/2012	15.50	2012-07-12	(19.00)	(3.50)	0.000055	(0.00019)
10	MHANNON1	REIMBURSE HEALTH CARE	9,908.00	2012-09-11	00121384	2012	9	1100	2012-09-11	9/1/2012	9/30/2012	15.00	2012-09-11	(19.00)	(4.00)	0.000115	(0.00046)
11	MHANNON-2000	REIMBURSE HEALTH CARE ACCT	10,264.00	2012-11-08	00124873	2012	11	1100	2012-11-08	11/1/2012	11/30/2012	15.00	2012-11-08	(22.00)	(7.00)	0.000119	(0.00083)
12																	
13	2012PEVEBACONT3	INS CONTRIB	4,190,790.00	2012-12-13	00000313	2012	12	1100	2012-12-18	1/1/2012	12/31/2012	183.00	2012-12-18	(13.00)	170.00	0.048549	8.25328
14	2012PEVEBACONT1	GROUP INSURANCE	14,110,176.00	2012-12-13	00000314	2012	12	1100	2012-12-18	1/1/2012	12/31/2012	183.00	2012-12-18	(13.00)	170.00	0.163461	27.78836
15	2012PEVEBACONT2	CONTRIB TO INS PLAN	473,053.00	2012-12-13	00000315	2012	12	1100	2012-12-18	1/1/2012	12/31/2012	183.00	2012-12-18	(13.00)	170.00	0.005480	0.93162
16	MHANNON	REIMBURSE HEALTH CARE ACCT	1,549.00	2012-12-27	00127668	2012	12	1100	2012-12-28	1/1/2012	12/31/2012	183.00	2012-12-28	(3.00)	180.00	0.000018	0.00323
17	MHANNON	REIMBURSE HEALTH CRE	(307.00)	2012-12-12	00126878	2012	12	1100	2012-12-13	1/1/2012	12/31/2012	183.00	2012-12-13	(18.00)	165.00	-0.000004	(0.00059)
18																	
19			86,321,388.00													1.000000	169.91

The Peoples Gas, Light and Coke Company
Adjustment For Invested Capital Taxes
For the Test Year Ending December 31, 2015
(In Thousands)

Line (A)	Description (B)	Amount (C)		Source (D)
1	Rate Base	$	1,670,732	App. B, p. 1, col. i, line 22
2	Rate of Return		6.59%	App. B, p. 1, col. i, line 23
3	Operating Income Required	$	110,101	Line 1 x Line 2
4	Pro forma operating income at present rates adjusted before ICT adjustment		68,485	App. B, p. 1, col. (d) line 21 - App. B, p. 2, col. (g) line 14
5	Operating Income Additional Allowed	$	41,616	Line 3 - line 4
6	Invested Capital Tax Rate		0.80%	PGL Schedule WPC-2.13
7	Incremental Invested Capital Tax Impact per Staff	$	333	Line 5 x line 6
8	Incremental Invested Capital Tax Impact per Company		473	NS-PGL Ex. 36.2 P. p. 2
9	Adjustment	$	(140)	Line 7 - line 8

Docket Nos. 14-0224/14-0225
(Consolidated)
ICC Staff Initial Brief
Attachment A

The Peoples Gas Light and Coke Company

Embedded Cost of Long-Term Debt

Net Proceeds Method
Test Year Ending December 31, 2015

Line No.	Debt Issue Type, Coupon Rate [A]			Date Issued [B]	Maturity Date [C]	Date Reacquired [D]	Principal Amount at Issuance [E]	New and Retired Time Weighted Face Amount Outstanding [F]	Thirteen Month Average Unamortized Discount or (Premium) [G]	Thirteen Month Average Unamortized Debt Expense (Gain) [H]		Carrying Value [I]=[F-G-H]	Coupon Interest Expense [J]=[A*F]	Amortization of Debt Discount or (Premium) (4) [K]	Amortization of Debt Expense (4) [L]		Total Expense [M]=[J+K+L]	Line No.
	Test Year Ending December 31, 2015 (1)																	
1	First and Refunding Mortgage Bonds:																	1
2																		2
3	Series RR	4.30%	(2)	06/01/05	06/01/35	-	50,000,000	50,000,000	-	690,000		49,310,000	2,150,000	-	35,000		2,185,000	3
4	Series TT	8.00%		11/03/08	11/01/18	-	5,000,000	5,000,000	-	21,000		4,979,000	400,000	-	6,000		406,000	4
5	Series UU	4.63%		09/30/09	09/01/19	-	75,000,000	75,000,000	-	324,000		74,676,000	3,473,000	-	78,000		3,551,000	5
6	Series WW	2.625%	(2)	10/05/10	02/01/33	08/01/15	50,000,000	29,167,000	-	304,000		28,863,000	766,000	-	16,000	(5)	782,000	6
7	Series XX	2.21%		11/01/11	11/01/16	-	50,000,000	50,000,000	-	149,000		49,851,000	1,105,000	-	112,000		1,217,000	7
8	Series YY	3.98%		12/04/12	12/01/42	-	100,000,000	100,000,000	-	893,000		99,107,000	3,980,000	-	33,000		4,013,000	8
9	Series ZZ	4.00%		04/18/13	02/01/33		50,000,000	50,000,000	-	695,000		49,305,000	2,000,000	-	40,000		2,040,000	9
10	Series AAA	3.96%		08/01/13	08/01/43	-	220,000,000	220,000,000	-	1,674,000		218,326,000	8,712,000	-	60,000		8,772,000	10
11	Series VV remarketing	3.90%	(2)	07/01/14	03/01/30	-	50,000,000	50,000,000	-	866,000		49,134,000	1,950,000	-	59,000		2,009,000	11
12	Series BBB	4.21%		11/03/14	11/01/44	-	200,000,000	200,000,000	-	1,423,000		198,577,000	8,420,000	-	49,000		8,469,000	12
13	Series WW remarketing	3.90%	(2)	08/01/15	02/01/33	-	50,000,000	20,833,000	-	342,000	(3)	20,491,000	812,000	-	22,000	(5)	834,000	13
14	Series CCC	4.66%		10/01/15	10/01/45	-	150,000,000	37,500,000	-	303,000	(3)	37,197,000	1,748,000	-	12,000	(5)	1,760,000	14
15	Future Issuance Fee	n/a		n/a	n/a	n/a	n/a	n/a	n/a	-	(6)	-	n/a	n/a	n/a		n/a	15
16	Sub-Total						1,050,000,000	887,500,000	-	7,684,000		879,816,000	35,516,000	-	522,000		36,038,000	16
17	Less: Amortization of Losses on Reacquired Bonds																	17
18	Series X	6.875%	(2)	03/01/85	02/01/33	03/14/03	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -		$ -	18
19	Series KK	5.000%	(2)	02/06/03	02/01/33	04/18/13	-	-	-	2,581,000	(7)	(2,581,000)	-	-	147,000	(7)	147,000	19
20	Series Y	7.50%	(2)	03/01/85	02/01/33	04/03/00	-	-	-	-		-	-	-	-		-	20
21	Series GG	Variable Rate	(2)	03/01/00	02/01/33	03/27/03	-	-	-	-		-	-	-	-		-	21
22	Series LL	3.75%	(2)	02/20/03	02/01/33	10/04/10	-	-	-	-		-	-	-	-		-	22
23	Series WW	2.625%	(2)	10/05/10	02/01/33	08/01/15	-	-	-	2,349,000	(8)	(2,349,000)	-	-	135,000	(8)	135,000	23
24	Series Z	7.50%	(2)	03/01/85	03/01/15	04/03/00	-	-	-	-		-	-	-	-		-	24
25	Series HH	4.75%	(2)	03/01/00	03/01/30	08/18/10	-	-	-	-		-	-	-	-		-	25
26	Series VV	4.75%	(2)	03/01/00	03/01/30	08/18/10	-	-	-	2,005,000	(9)	(2,005,000)	-	-	137,000	(7)(9)	137,000	26
27	Series AA	10.25%	(2)	03/01/85	06/01/35	08/01/95	-	-	-	-		-	-	-	-		-	27
28	Series FF	6.10%	(2)	06/01/95	06/01/35	06/02/05	-	-	-	2,020,000	(10)	(2,020,000)	-	-	101,000	(10)	101,000	28
29	Series BB	8.10%	(2)	05/01/90	10/01/37	05/01/00	-	-	-	-		-	-	-	-		-	29
30	Series II	Variable Rate	(2)	03/01/00	10/01/37	11/12/03	-	-	-	-		-	-	-	-		-	30
31	Series JJ 36%	Variable Rate	(2)	03/01/00	10/01/37	10/14/03	-	-	-	-		-	-	-	-		-	31
32	Series OO	Variable Rate	(2)	10/09/03	10/01/37	08/18/11	-	-	-	1,879,000	(11)	(1,879,000)	-	-	84,000	(11)	84,000	32
33	Series BB	8.10%	(2)	05/01/90	10/01/37	05/01/00	-	-	-	-		-	-	-	-		-	33
34	Series JJ 64%	Variable Rate	(2)	03/01/00	10/01/37	10/14/03	-	-	-	-		-	-	-	-		-	34
35	Series EE	Variable Rate	(2)	12/01/93	10/01/37	10/14/03	-	-	-	-		-	-	-	-		-	35
36	Series PP	Variable Rate	(2)	10/09/03	10/01/37	04/17/08	-	-	-	1,440,000	(12)	(1,440,000)	-	-	65,000	(12)	65,000	36
37	Series DD	5.75%	(2)	12/01/93	11/01/38	12/01/03	-	-	-	1,628,000		(1,628,000)	-	-	70,000		70,000	37
	Series QQ	4.88%		11/25/03	11/01/38	10/01/14	-	-		1,325,000		(1,325,000)	-	-	57,000		57,000	
38	Sub-Total						-	-	-	15,227,000		(15,227,000)	-	-	796,000		796,000	38
39	Total						$1,050,000,000	$ 887,500,000	$ -	$ 22,911,000		$ 864,589,000	$ 35,516,000	$ -	$ 1,318,000		$ 36,834,000	39
40	Embedded Cost of Long-Term Debt (M / I)																4.26% (13)	40

Notes: (1) Based on zero months of actual data and 12 months of forecasted data.
(2) Tax-exempt bonds.
(3) Total costs amortized based on life of the debt.
(4) Annualized amounts were created using the 12/31/11 amortization amounts multiplied by 12 months.
(5) Amount based on life of the debt.
(6) Fee paid for Docket 12-0285 not yet applied to a bond issuance.
(7) Refinancing Series combined (X and KK). Lines 18 and 19.
(8) Refinancing Series combined (Y, GG, LL, and WW). Lines 20 through 23.
(9) Refinancing Series combined (Z, HH, and VV). Lines 24 through 26.
(10) Refinancing Series combined (AA and FF). Lines 27 and 28.
(11) Refinancing Series combined (BB,II, JJ 36% and OO). Lines 29 through 32.
(12) Refinancing Series combined (BB, JJ 64%, EE, and PP). Lines 33 through 36.
(13) Proposed embedded cost of debt requested in this filing.