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	:	

REPLY 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 Reply Brief in the above-captioned matter.

The Initial Brief of the Staff of the Illinois Commerce Commission ("Staff's Initial Brief" or "Staff IB") was served on October 21, 2014. The Initial Brief of 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 "Utilities" or "Companies") ("NS-PGL IB", "Utilities' IB", or "Companies' IB"); the Initial Brief of The People of the State of Illinois *ex rel.* Lisa Madigan, Attorney General of the State of Illinois (the "AG") ("AG's Initial Brief" or "AG IB"); the joint Initial Brief of Citizens Utility Board ("CUB") and the City of Chicago ("City") (jointly "CUB-City") ("CUB-City's Initial Brief" or "CUB-City IB"); the Initial Brief of CUB, City and Illinois Industrial Energy Consumers ("IIEC") (jointly "CCI") ; the Initial

Brief of IIEC, and the Initial Brief of Environmental Law & Policy Center ("ELPC") were also served and filed on October 21, 2014.

Some of the issues raised in the parties' initial briefs were addressed in Staff's Initial Brief and, in the interest of avoiding unnecessary duplication, Staff has not repeated every argument or response previously made in Staff's Initial Brief. Thus, the omission of a response to an argument that Staff previously addressed simply means that Staff stand on the position taken in Staff's Initial Brief.

I. INTRODUCTION

A. Overview/Summary

II. TEST YEAR (Uncontested)

III. REVENUE REQUIREMENT

A. North Shore

B. Peoples Gas

C. Proposed Reorganization

In its Initial Brief, Staff explained why, based on the circumstances of the proposed merger and this proceeding's record, 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. 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. (Staff IB, 4-7.)

The AG posits that the lack of clarity around the Companies' future should raise the question of whether there should be any rate changes at this time. (AG IB, 13-15.) ("The People echo Mr. Effron's suggestions in urging the Commission to consider whether there should be any rate changes at this time of great uncertainty for 2015.") (*Id.*, 14.) If the AG is suggesting that legally the Commission cannot set new rates for the Companies given the alleged uncertainty of certain costs in the test year related to the pending reorganization, then the Commission should reject that argument. First, the AG cites no legal authority for that position. Second, even if there is some uncertainty about certain costs in the test year related to the merger, the Companies have presented evidence on a substantial number of other costs, some of which parties take issue. The PUA certainly allows the Commission to set rates based upon those other costs. ("If the Commission enters upon a hearing concerning the propriety of any proposed rate or other charge, … , the Commission shall establish the rates or other charges, …, 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).) (emphasis added) Accordingly, if the AG is suggesting that the Commission cannot legally set new rates given the pending reorganization, that argument should be rejected.

The CCI introduce six recommendations regarding the Reorganization in their Initial Brief. (CCI IB, 6-7.) Overall, Staff agrees with the Companies that the Reorganization Docket No. 14-0496 is the most appropriate place for the Commission to order conditions regarding the Reorganization. (NS-PGL IB, 16.) Should the Commission disagree and prefer to order some conditions in the instant proceeding, Staff presents its responses below. Staff further reserves the right to clarify or change its position based on information other parties may present in their Reply Briefs.

The CCI first recommend the Commission "order the Companies to report any significant change in their costs of providing regulated services, and any significant change in amounts allocated to the Companies from other affiliates, so the Commission can assess the appropriateness of possible orders to show cause why NS-PGL rates should not be reduced." (CCI IB, 6-7.) Staff does not oppose this recommendation, but suggests reporting instructions be added that the report should be a filing on the Commission's e-Docket system in this docket, with a copy to the Commission's Accounting Department Manager within thirty (30) days of the significant change.

Second, the CCI recommend the Commission "order the Companies to separately track and record all costs, whether expenses or investments, associated with the reorganization (including costs attributable to transitions to common accounting, computer, and other management systems, to mergers of organization structures, and consolidation of operations), so that the Commission can assure that costs unrelated to the Companies' provision of regulated services are not included in regulated rates." (Id.) Staff supports this recommendation so that information that may be needed in future proceedings is retained.

Third, the CCI recommend the Commission "order the Companies to report their actual costs and revenues, with costs attributable to the reorganization excluded and separately stated, with a view to prompt investigation (through show cause proceeding or otherwise—9-250; 9-202), if indicated, of whether the Companies' approved rates continue to be just and reasonable." (Id.) Staff is unclear as to when the CCI recommend this information be provided, but suggest that the information be provided at the time the Companies file their next general rate cases. If implemented, the timing and method of the filing should be clarified.

Fourth, the CCI recommend the Commission "order the Companies to file new rates by a date certain (or within a specified period after the reorganization) that reflect (through an appropriate test year) the changed conditions occasioned by the reorganization." (Id.) Again, Staff is unclear as to when the CCI recommend the rates be provided or what date might be appropriate, or how the Commission could order a specific test year if that is the intention. If implemented, the timing and method of the rate filing should be clarified.

Fifth, the CCI recommend the Commission "order the Companies (a) to limit any post-reorganization dividend pay-outs from the Companies to any affiliates to a level representative of pre-reorganization pay-outs and (b) to report any dividend pay-outs to the Commission within 30 days of such pay-outs." (Id.) Staff opposes any condition to limit post-reorganization activity before the Commission rules on the reorganization itself. However, Staff is not opposed to the Companies reporting dividends. Further, Staff believes it should not require 30 days for a utility to report dividend payments. If implemented, the report should be required as a filing on the Commission's e-Docket system in this docket, with a copy to the Commission's Finance Department Manager within five (5) business days of the dividend payment.

Sixth and last, the CCI recommend the Commission "order the Companies to report to the Commission, within 14 days of the change, any changes by credit rating agencies to their credit rates of, or their recommendations concerning, the Companies or any affiliates." (Id.) Staff supports this requirement as far as it applies to Integrys, Peoples Gas and North Shore; however Staff is concerned that the Commission could not rule on this requirement in this Docket a condition over WEC, prior to reorganization approval. If approved, the report should be required as a filing on the Commission's e-Docket system in this docket, with a copy to the Commission's Finance Department Manager within fourteen (14) days of the change. Further, Staff recommends the Commission broaden the CCI recommendation to require that the Companies to provide a copy of all reports the credit agencies issue on the Companies.

IV. RATE BASE

A. Overview/Summary/Totals

1. North Shore

2. Peoples Gas

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

1. Gross Utility Plant

a. 2013 Plant Balances[1]

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)

v. LNG Control System Upgrade (PGL)

vi. LNG Truck Loading Facility (PGL)

Peoples Gas now states that any Commission ruling on the Company's proposed LNG Truck Loading Facility is "premature" because "a categorical ruling by the Commission on any possible scope, scale, or structure of some yet to be designed and constructed LNG Truck Loading Facility runs the risk of the Commission requiring approvals that may not be applicable for a potential future development." (NS-PGL IB, 22-23.) Strangely, the Company seems to imply that the Truck Loading Facility proposal

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

is far from any specific plan of execution. Peoples Gas now describes the Facility as a "potential future development."

Peoples Gas proposed the LNG Truck Loading Facility in its Direct Testimony as part of its Gross Utility Plant to be recovered in rate base. Obviously the Company planned to commence the project and incur expenses sometime during 2015, its test year for this rate case, otherwise it would not have sought capitalized recovery for the Facility. In fact, the Company had included testimony that stated the facility would cost $4,000,000. (NS-PGL Ex. 30.0, 2:26-28.) Regardless, the Company withdrew the project from rate base, after Staff's objection in Direct Testimony. (Staff IB, 9.) Staff continues to recommend the Commission require Peoples seek approval from the Commission should it build the Facility. The Company still has not provided 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. 220 ILCS 5/7-102(A)(g). Staff continues to recommend the Commission include this language in its final order in this docket:

> 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.

(Staff IB, 11.) Such language is necessary to protect ratepayers and is appropriate since 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, could impact Peoples Gas' ability to adequately serve its customers.

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)

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

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)

Peoples Gas' criticisms on the adjustment of AG witness Effron to reflect a more reasonable forecast amount of 2014 AMRP additions in rate base should be rejected. The Company opines that the August 2014 additions support its AMRP forecast. (NS-PGL IB, 34.) Staff has filed a motion to take administrative notice of the actual 2014 AMRP additions for the remainder of the year. (Staff IB, 14.) The actual AMRP additions for the final quarter of 2014 should make clear whether or not the Company's forecast, or the AG's adjusted AMRP additions, are reasonable.[2]

Staff and the AG have described how the Company will recover its actual prudent costs of AMRP additions by use of an adjustment through Rider QIP. (Staff IB, 15; AG Corrected IB, 18.) The Company describes a potential adverse impact that could happen to future AMRP projects if the Company reaches the revenue cap to be set in this case pursuant to Section 9-220.3(g). (NS-PGL IB, 35.) However, the existence of the revenue cap does not eliminate the Commission's obligation to set rate base, and base rates, at a just and reasonable level. (220 ILCS 5/9-101) The shortfall of actual AMRP additions versus the Company's forecast (Staff IB, 15) cannot be ignored simply because a future revenue cap may one day be enforced. The impact on future AMRP projects is solely within the Company's control; Peoples Gas is not prohibited from filing for rate recovery under a traditional rate case should a revenue cap restriction on Rider QIP begin to influence its AMRP progress. Base rate revenues should determine the cap. The Company's position would flip that principle around and have the cap determine base rate revenues. This proposal by the Company is neither just nor reasonable.

[2] Staff believes the numbers at p. 21 of AG's Corrected IB inadvertently did not include the corrections at NS-PGL Ex. 37.5 P, as cited in Staff's IB and Appendix B.

2. Cash Working Capital

a. OPEB lead

The Companies argue that "in accordance with customary practice", they considered the timing of all payments made during the year of their lead/lag study, weighted them accordingly, and that Staff's substitution of one input in the study is flawed. (NS-PGL IB, 37.) The Companies state that Staff has no sound reason to modify only the OPEB lead payment date. (NS-PGL IB, 39.) Staff analyzed the support for the reasonableness of the OPEB lead. This is the customary practice in Commission proceedings. Here, Staff found, based on the evidence, that the OPEB positive leads of 170.00 and 169.91 for North Shore and Peoples Gas, respectively, which provide additional cash working capital due to the timing of the payments, are not reasonable. (Staff IB, 16.)

The Companies argue that Staff's adjustment is based solely on its subjective opinion that a payment made at the end of the year is more appropriate than one made at the Company's discretion. (NS-PGL IB, 37.) Neither the historical OPEB payment activity nor the lack of a required payment date are matters of conjecture or opinion. These are facts, which Staff properly analyzed, and from which it concluded it was unreasonable to provide increased cash to the Companies in future rates for a practice which is the anomaly, not the norm. (Staff IB, 16-17.)

Further, the Companies' complaints that Staff is being inconsistent with the position of Staff in Docket Nos. 12-0511/12-0512 (Cons.) ("Peoples Gas 2012") is a red herring. (NS-PGL IB, 38) The Companies themselves presented a different position in the instant cases, proposing negative leads of (99.06) and (66.64) days for Peoples Gas and North Shore, respectively,(Staff IB, 16) than in the Peoples Gas 2012 rate cases where zero lag days was proposed (Staff Ex. 6.0, 9.). Therefore, there was no reason for Staff in this case to analyze whether or not zero should be the appropriate lead days for OPEB CWC. Staff's position to analyze the new position of the Companies, rather than apply the conclusion from the Peoples Gas 2012 rate cases which was based on different facts and positions, is not inconsistent with the Peoples Gas 2012 rate cases. The Companies continue to present the misleading argument that the OPEB lead should really be zero-despite the results of their 2012 lead/lag study- based on the flawed assertion that this is required since the Companies have OPEB liabilities that reduce rate base. (NS-PGL IB, 39) The Companies are attempting to confuse the issue by relying on arguments from Peoples Gas 2012—arguments that were rejected by the Commission—to a different set of facts and proposals herein. (North Shore Gas Company and The Peoples Gas Light and Coke Company, ICC Order Docket Nos. 12-0511/12-0512 (Cons.), 80 (June 18, 2013)) Having never proposed a zero OPEB lead in this case, the Companies' conclusions as to the supposed relationship to the OPEB liability deduction to rate base are moot.

For these reasons and as discussed further in Staff's IB, the Commission should approve 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 CCI supports Staff's adjustment. (CCI IB, 9.)

3. Retirement Benefits, Net

The AG and CCI join Staff in the position that the facts of this case do not warrant any different conclusion on the issue of excluding the Companies' pension assets from rate base. (AG Corrected IB, 23; CCI IB, 10; Staff IB, 18-27.) The record reflects no reason to reconsider the past Commission conclusions and reverse course as the Companies request. (Id., NS-PGL IB, 41-42.) The Companies argue five reasons for reconsiderations of the Commission's prior Orders on this issue, however, these arguments are not new and provide no reason for the Commission to reconsider and changes its long standing position on this issue.

First, the Companies ask for reconsideration based on their erroneous conclusion from <u>N.Y. Bd. of Pub Util. Comm'rs v. New York Telephone Co.</u>, 271 U.S. 23, 46 S.Ct. 363, 70 L.Ed. 808 (1926) that there is no legal basis for treating earnings as ratepayer-supplied funds. (NS-PGL IB, 41.) The Commission has previously rejected the Companies' requests to reconsider based on this cite to an eighty-seven year old case, and should do so again here. Peoples Gas 2012, 81; <u>North Shore Gas Company and The Peoples Gas Light and Coke Company,</u> ICC Order Docket Nos. 11-0280/11-0281 (Cons.), 30 (January 10, 2012)("Peoples Gas 2011.")

The case cited by the Company, <u>New York Board of Public Utility Commissioners</u>*,* is essentially a retroactive ratemaking case. Staff is aware of the issue of retroactive ratemaking as well as Illinois case law on the issue. (*See*, <u>Mandel Brothers, Inc. v. Illinois Commerce Comm'n</u>, 2 Ill. 2d 205, 210 (1954) and a number of subsequent decisions (<u>Citizens Utilities Co. v. Illinois Commerce Comm'n</u>, 124 Ill. 2d 195, 206-211 (1988)). The Companies have not argued that Staff's position is retroactive ratemaking, which it is not; therefore, the eighty-seven year old case is not relevant to the issue in this case. The Companies are seeking to collect monies from ratepayers and then charge those ratepayers with a return on investment of those monies. What is relevant, which the Companies have not disputed, 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 and 91 (1960); DuPage Utility Co. v. Illinois Commerce Comm'n, 47 Ill. 2d 550, 554 and 558 (1971); and Central Illinois Light Co. v. Illinois Commerce Comm'n, 252 Ill. App. 3d 577, 583-3 (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)) (Staff IB, 26-27.) In addition, with respect to New York Board of Public Utility Commissioners, as long ago as 1975, the Federal Power Commission, the predecessor of the FERC, observed that accounting practices had changed substantially between the New York Telephone decision and the matter then under consideration, to the point where the Federal Power Commission found New York Telephone entirely distinguishable. Order on Rehearing, Municipal Light Boards of Reading and Wakefield, Massachusetts, et al., v. Boston Edison Company, 54 F.P.C. 440, 1975 WL 14328 (F.P.C. 1975).

Second, the Companies argue that ownership of the pension assets on their balance sheets allows for reconsideration. (NS-PGL IB, 41.) Staff has explained how ownership of the pension trust fund is not relevant. (Staff IB, 26.) The Commission previously considered and rejected this argument. (Peoples Gas 2012, 81; Peoples Gas 2011, 29-30.) This argument is not new, and not a basis for reconsideration.

Third, the Companies present as an argument for reconsideration the fact that the rates on which customers' bills are based reflect the accrual of pension expense. (NS-PGL IB, 41.) The fact that the Companies will receive the full amount of actuarially determined pension expense in the revenue requirement is not a basis to allow a return on ratepayer supplied funds. (Staff IB, 22-23.) Further, nothing has changed here, i.e., past Orders which rejected the Companies' position also determined rates based on the accrual of pension expense. (e.g., Peoples Gas 2012, 81.) Thus, this argument is not new nor a basis for reconsideration.

The fourth argument for reconsideration from the Companies is their theories on normal operating revenues and their relationship to retained earnings. (NS-PGL IB, 41.) The Companies highlight that this argument was raised both in Peoples Gas 2011 and 2012, omitting the fact that it was rejected by the Commission in both of those cases. (NS-PGL IB, 42.) Staff has discussed how the prior Orders are valid and that the Commission is not required to make a particular finding as to each evidentiary fact or claim made by a party. (Staff IB, 18-19.) Thus, this argument is not new and not a basis for reconsideration.

Finally, the Companies assert that cumulative pension contributions in excess of cumulative pension expense is a basis for reconsideration. (NS-PGL IB, 41.) The Commission has never allowed a return on a pension asset based on this type of historical analysis of pension contributions versus expense. (Staff IB, 22.) Nonetheless, the facts in this case are that Peoples Gas made no contributions into the qualified pension plan during 2013 and 2014, and the Companies' updated actuarial reports reflect zero employer contributions for the year 2015 for both utilities. (Staff IB, 23.)

The Companies seek to reverse prior Commission Orders that excluded pension assets from rate base, yet seek to uphold prior Orders that did not reflect rate base deductions for pension liabilities. (NS-PGL IB, 43[3].) This unsupported position allows the Companies to unjustly inflate rate base. Staff respectfully maintains that the evidence shows no relationship exists between the Companies' theories of pension asset and pension liabilities inclusion or exclusion from rate base. Staff's adjustment to North Shore's rate base properly excludes ($1,513,000) of 2015 pension liability from the average adjustment because such amount is a cost-free source of capital. (Staff Ex. 6.0, Sch. 6.09 N; Staff IB, 23-26.) Utility rate base should be reduced by any cost-free capital the utility employs; to do otherwise would be an unjust and unreasonable treatment of ratepayers. Staff's adjustments for both Peoples Gas and North Shore are proper, and should be adopted by the Commission.

V. OPERATING EXPENSES

A. Overview/Summary/Totals

1. North Shore

2. Peoples Gas

[3] The Companies are correct that the AG witness proposed to eliminate both the a) Peoples Gas pension asset and b) North Shore pension liability, however no elaboration on the position was provided. (Id., AG Ex. 7.1, 2; AG Ex. 7.2, 2). Staff believes the final sentence in the AG's Corrected IB describing the North Shore adjustment is in error, and is reversed. (AG Corrected IB, 23.)

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

1. Other Revenues

2. Resolved Items

a. Incentive Compensation

b. Executive Perquisites

c. Interest

i. Budget Payment Plan

ii. Customer Deposits

iii. Synchronization (including derivative adjustments)

d. Lobbying

e. Fines and Penalties

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)

The Companies and Staff agree on the total amount of rate case costs to be recovered from ratepayers but disagree on the period over which such costs are to be amortized. Accordingly, the Companies' IB provides almost identical language for the Commission order that Staff recommends in its IB except for the amount of amortized rate case expense to be included in the revenue requirements. The amount of amortized rate case expense is a contested issue addressed in Section V.C.4 of this reply brief.

The Companies' IB also proposes the addition of the sentence: "The total rate case costs are detailed in NS-PGL Exs. 36.4N and 36.4P." (NS-PGL IB, 66.) This additional sentence is acceptable to Staff.

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

15. Income Taxes (including derivative impacts)

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

17. Gross Revenue Conversion Factor

18. Other

a. Invested Capital Tax

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

1. Test Year Employee Levels

a. Peoples Gas

b. North Shore

2. Medical Benefits

a. Peoples Gas

b. North Shore

c. IBS

3. Other Administrative & General

a. Integrys Business Support Costs

i. Labor

ii. Benefits

iii. Postage

iv. Legal (NS)

v. ICE Project

(a) Return on Assets and Depreciation

(b) Non-Labor

The Companies discuss the flaws in the AG's 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. (NS-PGL IB, 79-81.) The AG ignores the evidence of the timing of the ICE project's implementation, and the substantial progress incurred to date. (Id., Staff IB, 35-36.) Further, the evidence does not support the notion that implementation of an integrated customer system will lead to cost savings in the test year from the potential Reorganization. (Id., NS-PGL IB, 80.) Therefore, the AG's adjustments should be rejected.

b. Advertising Expenses

The Commission should adopt Staff's rebuttal adjustment to eliminate advertising expenses that are of a promotional, goodwill or institutional nature. The expenditures in question are not eligible for recovery as advertising expenses under Section 9-225 of the Public Utilities Act ("Act"). (Staff IB, 36-37.)

The Companies acknowledge that the expenditures in question are not eligible for recovery as advertising expenses but argue the Companies should be allowed to recover the expenditures because the advertising expenditures might qualify as charitable contributions under Section 9-227 of the Act. (NS-PGL IB, 82.) The Companies' rationalization forces them to create an "expanded description" of the advertising expenditures so that the Companies can attempt to recover their ineligible expenditures in spite of the Act's prohibition. (NS-PGL IB, 85.)

The Commission should reject this rationalization. First, since the Companies requested recovery of these expenditures as advertising expenses under Section 9-225 of the Act, that is how the Commission should evaluate the expenditures. There is not time in an 11-month rate case schedule to adequately or timely review the expenditures for compliance as advertising expenditures under Section 9-225 of the Act and, alternatively, as charitable contributions under Section 9-227 of the Act. Second, the Commission should not reward the Companies for ignoring the Commission's direction on this issue in the Companies' last rate case that 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. The Companies, however, did not follow this direction. (Staff IB, 37-38.)

c. Institutional Events

The Commission should not allow the Companies to recover, through rates, 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 Act. (Staff IB, 38-39.)

As with advertising expenses, the Companies argue that an expenditure for an institutional event that is not recoverable as filed should be allowed to be recovered if it can be rationalized to be of a charitable nature. As with advertising expenditures, the Companies’ are encouraging the Commission to rely on an “expanded description” to allow recovery of ineligible expenditures in spite of the Act’s prohibition. (NS-PGL IB, 87.)

As with advertising expenses, there is not sufficient time in the schedule to allow the opportunity to adequately or timely review these expenditures for compliance as anything other than as institutional events. Allowing the Companies to file a rate case with expenditures classified as institutional events, and then allowing the expenditures to be considered as charitable expenditures, 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. (Staff IB, 39.)

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's adjustment comports with numerous past Commission rulings on the recovery of the Companies' charitable contributions. (Staff IB, 40.)

The Companies make several attempts to find a justification for recovery of the contributions in question; however, the Companies do not make an argument that the contributions provide tangible benefit to ratepayers in the Companies' service territory. The Companies also make several arguments to emphasize the benefit to those receiving the contributions. No one has questioned the benefits of the contributions to the general public, but contributions that do not benefit specific NS-PGL ratepayers should not be included in the revenue requirement to be paid by those ratepayers. (NS-PGL, IB, 88-91.)

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. (Staff IB, 40-41.)

The Companies claim that these expenditures provide benefits to customers in an indirect way by allowing the Companies to interact with other business and governmental entities to develop contacts, exchange ideas, coordinate current projects, maintain and continue to develop infrastructure within its service territories. (NS-PGL, IB 91-92.) The Companies have provided no documentation that this claim is actually correct. The Companies require the Commission to take this assumption as fact when there are unlimited ways for the Company employees to maintain contacts with other business and governmental entities without providing select Company employees the benefits associated with attending social events sponsored by these social and service clubs. Social and service clubs by their very nature represent gratuitous actions by their members to make the community a better place. Granting the utilities recovery of these expenses is contrary to what social and civic clubs symbolize.

4. Amortization Period for Rate Case Expenses

The Commission should adopt two and a half years as the amortization period for rate case costs. Based on the information available to the Commission, two and a half years is the most likely minimum period that rates established in this proceeding will be in effect. (Staff IB, 41.)

The Companies' propose a two year amortization period for rate case costs. (NS-PGL, IB, 92.) Staff did not take issue with the amortization period in its direct testimony. In rebuttal testimony, however, Staff noted new evidence which calls for an amortization period of no less than two and a half years. (Staff IB, 41.)

In their surrebuttal testimony, the Companies suggest that Staff's proposal is speculative. Other than characterizing Staff's position as speculative, the Companies ignore the additional evidence presented by Staff. The Companies also fail to present an argument that its proposed two year period is a better estimate than Staff's proposed two and a half year period for which rates established in this proceeding will be in effect.

(NS-PGL, IB, 92.) While the outcome of the merger case is unknown, Staff cannot recall a merger petition which was denied. (Staff IB, 42.)

5. Peer Group Analyses

VI. RATE OF RETURN

A. Overview

The Companies claim that their proposed increases to their authorized overall rates of return are consistent with the evidence that their costs of capital will be higher in 2015 than they currently are and what they were when the Utilities' rates were last set in 2013. (NS-PGL IB, 95.) However, the Companies' higher cost of capital recommendations rely on projections of interest rates that so far have proven to be upwardly biased. Since the future is unknown and the Company's interest rate forecasts have proven to be consistently too high, the Commission should rely on current observable market data to determine the appropriate overall rate of return for the Companies and adopt Staff's cost of capital recommendations.

B. Capital Structure

Staff accepted the Companies' proposed capital structures, hence this issue is uncontested. (Staff IB, 43; NS-PGL IB, 95-96.)

C. Cost of Short-Term Debt

The Companies insist that forecasted interest rates should be used to estimate their capital costs in 2015 because the forecasted interest rates are "used by investors to formulate their expectations of the future." (NS-PGL IB, 96.) They further assert that

Staff's reliance on historical "spot day" measurements are arbitrary and unreliable and should be rejected. *Id.* Contrary to the Companies claims, an analyst's use of the latest available data at the time of her analysis is not arbitrary. The most recent interest rate is the only interest rate that can fully reflect all the information currently available and is therefore the best indicator of a future interest rate. Since no one can accurately predict the future and the there are numerous forecasts available, choosing which forecast to use is arbitrary - the analyst could choose whatever forecast better suited her needs. The Companies did not show that the forecasts they relied on were reasonable. To the contrary, Staff showed that the Companies' forecasts have been atrociously wrong and resulted in overstated interest rates. (Staff IB, 44-45; 46-49.)

The Companies claim that Staff's position that current interest rates are better predictors of future interest rates than published forecasts is a fallacy because the accuracy of forecasts can only be determined with hindsight. They further claim that whether or not the forecast proved accurate with hindsight, the credibility and objectivity of the forecast is what matters. (NS-PGL IB, 97-98.) No one can forecast with any certainty the timing, direction, or magnitude of interest rate changes, however. Interest rates are constantly adjusting and accurately forecasting the movements in interest rates is problematic. Further, it is only through testing a forecaster's accuracy that its credibility can be ascertained. (The Companies offer no alternative test of credibility.) Since the accuracy of the forecast can only be determined in hindsight, using forecasted interest rates adds further ambiguity to the costs since those projections may not reflect investor expectations. Use of actual current interest rates eliminates the ambiguity because it reflects actual and current investor expectations regarding future interest rates.

D. Cost of Long-Term Debt

The Companies claim that Staff adopted an inconsistent approach by using the actual interest rate obtained on the Series VV municipal bond remarketing as a proxy interest rate for the Series WW municipal bond remarketing instead of adjusting for the difference in years to maturity as Ms. Freetly did in her direct testimony. (NS-PGL IB, 100.) In direct testimony, Staff calculated the average incremental yield for each year between 15-year and 20-year municipal bonds at 0.07%. (Staff Ex. 3.0, 6-7.) To reflect the additional two years to maturity for the Series WW, Staff agrees to increase the actual 3.90% interest rate on Series VV by the same increment, 0.14% (0.07% x 2), that it added to the Series VV bonds in direct testimony. Hence, the Series WW interest rate should be increased to 4.04%, as shown on line 13 of Attachment A to this Reply Brief. Even with this revision, Staff's estimate of People Gas' embedded cost of long-term debt remains 4.26%.

E. Cost of Common Equity

The Companies claim that other authorized returns should be considered as "indicators" to ensure that the return set in an individual case meets constitutional standards. (NS-PGL IB, 104.) The returns authorized for other utilities should only be used as indicators when all of the facts of the rate proceedings in which the return was set are comparable, since the rate of return on common equity is influenced by the regulatory structure of other states. For example, while the Companies used a future test year in this proceeding, some states do not allow future test years. Use of a future test year reduces regulatory lag and leads to more desirable rate outcomes, which is presumably why the Companies chose to use a future test year in this proceeding. Further, Mr. Moul failed to identify other crucial factors that influenced the allowed returns in those proceedings, such as the relative risk of the utilities involved in those return decisions as compared to the Companies. Since there is no basis on which to assess comparability, evaluation of the return recommendations in this proceeding via comparison to the returns authorized for other natural gas utilities is useless. (Staff IB, 56.)

In the Companies 2007 rate cases, the Commission rejected the Companies' push to use previously approved returns for other utilities as a guide for determining the investor-required rate of return in a rate setting proceeding. The Final Order in those proceedings states:

> [B]y determining the Utilities' ROEs via comparison to existing ROEs, the Commission would be disregarding its duty to impose only cost-based and reasonable rates on the Utilities' customers….It would require us to abandon the course we, along with other commissions, have charted for decades. Return determinations are appropriately based on a two-pronged analysis of utility-specific financial characteristics and financial market dynamics and conditions. We have relied upon the financial models and reasonable adjustments to accomplish this. Although even these quantitative mechanisms involve some degree of subjectivity and can, for that reason, be manipulated, they were constructed with the intention of objectively estimating the cost of equity, not to match another utility's ROE. (Order, Docket Nos. 07-0241/07-0242 Cons., February 5, 2008, 84.)

DCF

Although Ms. Freetly stated that for her DCF analysis she was adopting Mr. Moul's dividend yield to eliminate a contested issue, (Staff IB, 50) the Companies point out that Mr. Moul's actual dividend yield was 4.00%, not the 3.89% that Ms. Freetly used in her rebuttal testimony. (NS-PGL IB, 107.) Staff agrees that the 4.00% dividend yield should have been used in Ms. Freetly's revised DCF estimate. Adding the 4.00% dividend yield to Staff's 4.82% growth rate produces a DCF cost of equity estimate of 8.82%. This revised estimate is only 3 basis points below Staff's original DCF estimate of 8.85% from direct, which employed spot stock prices from October 31, 2013. (Staff Ex. 3.0, Schedule 3.04.) This shows that the spot data Staff employed is not abnormal as the Company claims. (NS-PGL IB, 96; 103)

The Companies contend that Staff's use of Value Line dividends per share ("dps") forecasts resulted in double counting the forecasted reduction in dividend yields for the Delivery Group, which reduced the DCF result. (NS-PGL IB, 108-109.) Not only is there no citation to the record for this new argument, the Company did not explain how the inclusion of the dps growth forecasts results in double counting the alleged forecasted reduction in dividends. In fact, there is no "forecasted reduction in dividends" since none of the forecasts of growth are negative. There is no citation to the record because Mr. Moul did not make this argument in testimony. The absence of any explanation makes it impossible for Staff to appropriately respond to the Companies' assertion.[4]

Further, ignoring the slowing growth in dividends per share would lead to an inflated estimate of the investor-required rate of return on common equity. Mr. Moul stated: "In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings,

[4] Staff is not addressing whether the Company's argument should be stricken since its lack of evidentiary support is so obvious.

dividends, book value, and cash flow on a per share basis." (NS Ex. 3.0, 16, emphasis added.) "Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth." (NS Ex. 3.0, 18, emphasis added.) Although he presented a variety of growth rates (NS Ex. 3.8) and acknowledged that a variety of factors should be examined to reach a conclusion on the DCF growth rate (NS Ex. 3.0, 19), he ignores all but the forecast of earnings per share growth, which results in a higher DCF estimate of the cost of common equity. Because the DCF is a *dividend* discount model, the expected growth in dividends must be correctly reflected to estimate the investor-required rate of return on common equity.

CAPM

The Companies argue that Staff's CAPM is fundamentally flawed due to Staff's use of spot day interest rates and lower beta estimate. (NS-PGL IB, 111.) The Companies falsely contend that the interest rate forecasts are "verifiable and unbiased" and superior to relying solely on spot day data to establish the cost of equity in a future test year. (NS-PGL IB, 112.) The Companies misunderstand the meaning of "bias", which is "a systematic as opposed to a random distortion of a statistic."[5] As can be seen in Table 1 on page 5 of Ms. Freetly's Rebuttal testimony (Staff Ex. 8.0), Blue Chip's forecasts of interest rates upon which the Companies rely (whether of 10-year U.S. Treasuries, 30-year U.S. Treasuries, Aaa corporate bonds, or Baa corporate bonds) have consistently overestimated the actual, realized interest rate. Thus, the

[5] http://dictionary.reference.com/browse/bias.

definition of “bias” clearly applies to Blue Chip’s forecasts of interest rates.[6] Hence, the Companies claim that the interest rate forecasts it relied upon are “unbiased” is demonstrably false.

Further, the record shows that Staff’s spot interest rate of 3.66% on October 31, 2013 (Staff IB, 53) is certainly not an anomaly or an outlier. To the contrary, that 3.66% yield is only 2 basis points above the actual 30-year U.S. Treasury bond yield averaged over three quarters ending June 30, 2014. In fact, the actual yield on 30-year Treasury bonds declined to 3.44% for the second quarter of 2014. (Staff IB, 47.) This comparison shows that Staff’s risk-free rate is not too low contrary to the Companies’ claim.

There is no valid justification for disregarding investor expectations imbedded in objective, observable current market data in favor of a proxy for those expectations imbedded in speculative projections. It is important to note that spot T-bond yields directly reflect the expectations of investors, while Blue Chip forecasts of T-bond yields do not. That is, investors’ buy and sell decisions set the T-bond yield, thereby revealing their expectations, whereas Blue Chip forecasts of T-bond yields merely reflect the opinions of a limited number of analysts, made with no direct financial interest in the yields they are predicting. Thus, the forecasts Mr. Moul advocates are merely proxies for investor expectations. Proxies are a source of measurement error in cost of common equity estimation. Therefore, proxies should only be used when the market factor in question is not directly observable. Since market expectations for T-bond yields

[6] Table 1 on page 40 of Staff’s IB shows that the Blue Chip forecasts for the fourth quarter of 2013 are lower than the realized interest rates. Of course, forecast accuracy should increase when the “forecast” for the quarter is dated one month <u>after</u> the quarter begins. (NS Ex. 3.12, 2.)

are directly observable, proxies for those expectations, such as a Blue Chip forecast, should not be used. Moreover, the current U.S. Treasury yields Ms. Freetly used to measure GDP growth reflect all relevant, publicly-available information. Consequently, any influence Blue Chip forecasts might have on investor expectations is already reflected in the current U.S. Treasury yields.

The Companies claim that Staff's betas are biased downward and only serve to lower Staff's CAPM results. (NS-PGL IB, 111-113.) However, as Staff explained in its Initial Brief, which beta estimates are more accurate is unknown. The Companies did not present any evidence that the Value Line betas are superior to Staff's. Since there is no inherently superior beta estimation methodology, multiple approaches result in less bias than merely relying on the higher Value Line betas. Hence, the Commission should remain consistent with its past findings that use of multiple beta sources is beneficial to reduce measurement error and adopt Staff's beta in this proceeding. (Staff IB, 53-55.)

F. Weighted Average Cost of Capital

In response to the Companies' IB, Staff agrees to adjust the interest rate on the Series WW remarketing to 4.04% to reflect an additional two years to maturity than the Series VV remarketing (see line 13 of Attachment A to Staff's Reply Brief), which does not alter Staff's 4.26% embedded cost of long-term debt recommendation for Peoples Gas. Further, Staff agrees that the correct dividend yield for the DCF should be 4.00% (instead of 3.89%), which results in a revised DCF estimate of 8.82%. Staff's revised investor-required rate of return of 9.05% was derived by taking the average of Staff's revised 8.82% DCF estimate and 9.27% CAPM estimate results. Staff's revised overall cost of capital recommendation, incorporating the uncontested capital structures and Staff's recommended costs of short-term debt, long-term debt, and common equity, equals 6.26% for North Shore and 6.56% for Peoples Gas. 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%	9.05%	4.57%
Total Capital	$204,897,000	100.00%		
Weighted Average Cost of Capital				**6.26%**

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%	9.05%	4.55%
Total Capital	$1,859,004,000	100.00%		
Weighted Average Cost of Capital				**6.56%**

VII. OPERATIONS

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

B. Pipeline Safety-Related Training (Uncontested)

VIII. COST OF SERVICE

A. Overview

B. Embedded Cost of Service Study

1. Allocation of Demand-Classified Transmission and Distribution Costs

The Commission should accept the Companies' proposed ECOS studies and reject the IIEC's criticisms against the 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's proposed CP allocator should be rejected. The IIEC has provided similar arguments in past cases against the studies and they have been consistently refuted by parties and rejected by the Commission.

IIEC witness Collins states that technical evidence has not been presented in this proceeding that supports the use of the average and peak ("A&P")[7] method for allocating the Companies' capacity related T&D system costs. He instead proposes that the Coincident Peak ("CP")[8] cost allocation methodology be used. (IIEC IB, 6.)

[7] 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.

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

However, both Staff and the Companies have provided clear evidence why the A&P allocation methodology should be continued and the CP methodology rejected. 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. (Id., 8.) Second, he opines that the A&P cost allocation method does not appropriately reflect how costs are incurred by the Companies. (Id., 12.)

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 double counts average demand, Ms. Hoffman Malueg disagrees and explains 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 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 it with 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 IB, 73.)

The Commission addressed IIEC's double counting argument previously 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*.)

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 method 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*., 74.)

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 of the year, but for every day of the year that gas is consumed which is what the average demand component reflects. *Id*.

Additionally, there is strong precedent in Illinois for using the A&P demand allocator. 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")[9] 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).

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

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.[10] 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*., 75.)

IIEC witness Collins states that the average demand component of the A&P allocator is given considerably more weight in the allocation of T&D capacity cost than CP demands, which are the primary load characteristics that explains cost causation. (IIEC IB, 12.) However, as Staff discussed in rebuttal testimony, peak day demands are an important determinant of T&D costs and are in fact a large part of the A&P allocator. The Companies' A&P allocation methodology utilizes 77% of CP demands for PGL and 74% of CP demands for NS. (Staff Ex. 8.0, 26.)

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

[10] 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.)

The Commission should reject IIEC's proposed CP allocation methodology for transmission and distribution plant and accept the Companies' proposed ECOS studies.

2. Allocation of Small Diameter Main Service Costs

IX. RATE DESIGN

A. Overview

B. General Rate Design

1. Allocation of Rate Increase

The Commission should accept Staff's and the Companies' proposed allocation methodology for any rate increases ordered in these proceedings. 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, using the formulas reflected in the supporting rate design work papers. (Staff IB, 79.)

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.*

2. Fixed Cost Recovery

Staff has not changed its position on the issue of fixed cost recovery. The Commission should reject the Companies' proposed movement towards greater fixed cost recovery. (NS-PGL IB, 125.) The Commission should accept Staff's and the AG's recommendation to begin moving away from a straight fixed variable ("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 encourages 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 IB, 81.) 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 IB, 81.)

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). (*Id*., 81-82.)

The Companies' argue that the Commission has endorsed policies in several rate proceedings to increase the fixed cost recovery through fixed charges. (NS-PGL, 125.) However, the Companies' argument fails to consider the Commission's current approach. Besides the ComEd case just referenced (Docket No. 13-0387), 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 had 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). (*Id*., 82.)

The Commission subsequently granted rehearing in Docket No. 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). (Staff IB, 83-84.) 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 encourage 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*.

Staff witness 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*., 84.)

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. (*Id*., 85.) 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' continue to argue that 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. (NS-PGL IB, 127.) They also state that when the Companies installs a main to serve a residential customer, the cost of that main, included in setting he revenue requirement that will underlie rates in this 2015 test year case, will not change from day-to-day or year-to-year simply because the customer uses more or less gas on the peak day or any other day. (*Id.*, 123.)

The Companies' 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. When demand costs are recovered through the customer charge, all customers are assumed to cost the same for the Companies to serve them. (Staff IB, 87.) When 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. (*Id.*, 87-88.)

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*[11].

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

> (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*.

Therefore, for all the above reasons the Commission should reject the Companies' proposed movement towards greater fixed cost recovery and accept Staff's and the AG's recommendation to begin moving away from a SFV-based rate design.

C. Service Classification Rate Design

1. Uncontested Issues

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

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

2. Contested Issues – North Shore and Peoples Gas

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

Staff has not changed its position on this issue. 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' IB states that their S.C. No. 1 NH class proposals are consistent with the Commission policy of gradually increasing fixed cost recovery in fixed charges. (NS-PGL, 129.) However, as Staff has shown, 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. (Staff IB, 92.) (Commonwealth Edison Co., ICC Order Docket No. 13-0387, 75 (December 18, 2013 and Ameren Illinois Company, ICC Order On Rehearing Docket No. 13-0476, 41 (September 30, 2014).

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 IB, 90-91.)

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*., 91.) 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.

The Companies also incorrectly state that Staff's proposal exacerbates the extent to which a customer's bill does not reflect the costs it causes the Utilities to incur, i.e., customer usage would drive fixed cost recovery but usage does not drive the Utilities' incurrence of those fixed costs. (NS-PGL IB, 129.)

Staff witness Johnson continually 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). Staff opined that a traditional rate design approach more closely aligns rates with cost causation principles. 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. (Staff IB, 92.)

AG/ELPC states that Staff's S.C. No. 1 NH rate design proposal does not go far enough and that Staff's rejection of the AG/ELPC's proposed 75% fixed cost recovery for the S.C. No. 1 NH class does not take into consideration the public policy goals of promoting conservation and energy efficiency. (AG/ELPC IB, 104-105.)

However, as Staff has stated, it is not clear how Mr. Rubin derived the 75% figure for non-heating customers. There may be public policy reasons for setting the fixed cost recovery at 75% but unfortunately the AG/ELPC did not provide any evidence to verify that 75% is a sound figure. As AG/ELPC witness Mr. Rubin states, PGL's ECOS study shows that 93% of non-heating costs are customer related. (AG/ELPC Ex. 3.0, 16.) He also states that NS' ECOS study shows 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 IB, 93.)

Therefore, 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.

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

Staff has not changed its position on this issue. 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.

The Companies' IB states that their S.C. No. 1 NH class proposals are consistent with the Commission policy of gradually increasing fixed cost recovery in fixed charges. (NS-PGL IB, 129-130.) However, as Staff has shown, 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. (Staff IB, 92.) (Commonwealth Edison Co., ICC Order Docket No. 13-0387, 75 (December 18, 2013 and Ameren Illinois Company, ICC Order On Rehearing Docket No. 13-0476, 41 (September 30, 2014).

The Companies also incorrectly state that Staff's proposal exacerbates the extent to which a customer's bill does not reflect the costs it causes the Utilities to incur, i.e., customer usage would drive fixed cost recovery but usage does not drive the Utilities' incurrence of those fixed costs. (NS-PGL IB, 130.) 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 IB, 95.) 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.* 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. Staff's proposed rates are based upon the Companies' proposed direct testimony revenue requirement. (Staff IB, 95-96.)

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 placing greater demands on the system 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.[12] 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*.

AG/ELPC states that Staff's S.C. No. 1 HTG rate design proposal does not go far enough and that Staff's rejection of the AG/ELPC's proposed 50% fixed cost recovery for the S.C. No. 1 HTG class does not take into consideration the public policy goals of promoting conservation and energy efficiency. (AG/ELPC IB, 104-105.)

However, as Staff has stated, it is not clear how Mr. Rubin derived the 50% figure for heating customers. There may be public policy reasons for setting the fixed cost recovery at 50% but unfortunately the AG/ELPC did not provide any evidence to verify that 50% is a sound figure. As AG/ELPC witness Mr. Rubin states, PGL's ECOS study shows that 64% of heating costs are customer related. (AG/ELPC Ex. 3.0, 16.) He also states that NS' ECOS study shows 67% of heating costs are customer related. (*Id*., 27.) Mr. Rubin emphasizes that these are the maximum amount of costs that should be

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

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 IB, 98.)

Therefore, 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.

c. Service Classification No. 2, General Service

Staff has not changed its position on this issue. 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.

The Companies' IB simply states that their S.C. No. 2 proposals are consistent with their rate design objectives, including fixed cost recovery in fixed charges. (NS-PGL IB, 131.)

However, Staff pointed out 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 IB, 100.) 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*., 100-101.)

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%.[13] 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 31%.[14] 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-

[13] 40% ≈ 45% - (45% X 10%).

[14] 31% ≈ 35% - (35% X 10%).

storage related demand costs would be recovered through the Company's proposed declining two-block per therm rate design. (Staff IB, 101-102.)

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,[15] 40% for Meter Class 2,[16] and 9% for Meter Class 3.[17] 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.*, 102-103.)

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 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. (*Id.*, 102-103.)

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[15] 36% ≈ 40% - (40% X 10%).

[16] 40% ≈ 45% - (45% X 10%).

[17] 9% ≈ 10% - (10% X 10%).

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 and bill comparisons 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. (*Id.*, 103.)

In Scenario 2, rates and bill comparisons 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. *Id*.

In Scenario 3, rates and bill comparisons 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. Id.

The Commission should adopt Staff's S.C. No. 2 class proposal. Staff's proposal starts the movement away from a SFV-based rate design while taking into consideration customer bill impacts and revenue stability for the Company.

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

Staff has not changed its position on this issue. The Commission should accept Staff's S.C. No. 4 rate design proposal.

The Companies' IB simply states that the Commission should approve their S.C. No. 4 proposals because they show movement towards greater fixed cost recovery in fixed charges. (NS-PGL IB, 132.)

As Staff has consistently stated throughout this proceeding, Staff has no objection to the Company's rate design proposal for the S. C. No. 4 rate class unless 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. If that occurs then Staff proposes that the final customer charge should be lowered to recover ECOS study customer costs only. 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. (Staff IB, 105.) Staff opined that the Companies' 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). (Staff IB, 92.)

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

Staff has no objection to the Commission directing the Companies to examine whether Heating and Non-Heating customers are classified correctly. However, in making this decision, Staff recommends the Commission take into consideration the additional information provided by the Company in its surrebuttal testimony, which indicates that an in-depth study would almost certainly be millions of dollars and a large commitment of personnel and time. (NS-PGL Ex. 46.0, 3-4.)

AG/ELPC witness Rubin testified that there may be residential customers who are misclassified as between heating and non-heating. (AG IB, 106.) 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*., 110.) The AG/ELPC recommends that the Commission order the Companies to Audit their residential classifications of customers. (*Id*., 113.)

The Companies explained that they have long-standing processes, predating the introduction of S.C. No. 1 non-heating and heating rates, to identify the customer's appliances. These processes include inquiries when an applicant or customer interacts with a customer service representative and a physical inspection of the premises. A sample that the Utilities reviewed showed that, overwhelmingly and to the extent they had definitive data, customers were correctly classified. While it is certainly possible that some customers are misclassified, it is not likely that 100% accuracy, 100% of the time is achievable, even if the Utilities conducted the suggested study. (NS-PGL IB, 133.)

The AG stated that 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. (AG IB, 112.)

However, Staff witness Johnson also 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. (Staff IB, 30-31.)

The Companies, in response to Staff, were unable to develop a cost estimate, but they explained that the large number of accounts that could require intensive manual review or physical inspections of the premises, or both, suggests that the costs of an in-depth study would almost certainly be millions of dollars and a large commitment of personnel and time. The Utilities further explained that, given the processes already in place and the large number of customers that are already subject to review on an annual basis as part of the application process, a study is not needed. (NS-PGL IB, 133.) However, in the Companies surrebuttal testimony 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. (NS-PGL Ex. 46.0, 5.)

Staff has no objection to the Commission directing the Companies to examine whether Heating and Non-Heating customers are classified correctly. However, in making this decision, Staff recommends the Commission take into consideration the additional information provided by the Company in its surrebuttal testimony, which indicates that an in-depth study would almost certainly be millions of dollars and a large commitment of personnel and time. (NS-PGL Ex. 46.0, 3-4.)

D. Other Rate Design Issues

1. Terms and Conditions of Service

a. Service Activation

b. Service Reconnection Charges

c. Second Pulse Data Capability Charge

2. Riders

a. Rider 5, Gas Service Pipe

b. Rider SSC, Storage Service Charge

c. Rider QIP, Qualifying Infrastructure Plant [PGL]

Staff's proposed language changes to the Companies' Rider QIP and to the findings/ordering paragraph addressing this rider in the Final Order to be issued in the instant proceeding are uncontested. (NS-PGL IB, 136-137, Staff IB, 114-115.)

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

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

November 6, 2014

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			Date Issued	Maturity Date	Date Reacquired	Principal Amount at Issuance	New and Retired Time Weighted Face Amount Outstanding	Thirteen Month Average Unamortized Discount or (Premium)	Thirteen Month Average Unamortized Debt Expense (Gain)		Carrying Value	Coupon Interest Expense	Amortization of Debt Discount or (Premium) (4)	Amortization of Debt Expense (4)		Total Expense	Line No.
	[A]			[B]	[C]	[D]	[E]	[F]	[G]	[H]		[I]=[F-G-H]	[J]=[A*F]	[K]	[L]		[M]=[J+K+L]	
	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	4.04%	(2)	08/01/15	02/01/33	-	50,000,000	20,833,000	-	342,000	(3)	20,491,000	842,000	-	22,000	(5)	864,000	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	35,546,000	-	522,000		36,068,000	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	$ 35,546,000	$ -	$ 1,318,000		$ 36,864,000	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.