STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	**:**	
	:	**12-0511**
Proposed general increase in natural gas	**:**	
rates. (Tariffs filed on July 31, 2012)	**:**	
	:	
The Peoples Gas Light and Coke Company	**:**	**12-0512**
	:	
Proposed general increase in natural gas	**:**	**Cons.**
rates. (Tariffs filed on July 31, 2012)	**:**	

PROPOSED ORDER

April 26, 2013

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STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

North Shore Gas Company	:	
	:	**12-0511**
Proposed general increase in natural gas rates. (Tariffs filed on July 31, 2012)	:	
	:	
The Peoples Gas Light and Coke Company	:	**12-0512**
	:	
Proposed general increase in natural gas rates. (Tariffs filed on July 31, 2012)	:	**Cons.**

PROPOSED ORDER

By the Commission:

I. Introduction

A. Procedural History

On July 31, 2012, North Shore Gas Company ("North Shore" or "NS") filed with the Illinois Commerce Commission ("Commission"), pursuant to Section 9-201 of the Public Utilities Act (the "Act" or the "PUA") (220 ILCS 5/9-201), the following revised tariff sheets: ILL. C.C. No. 17, Title Sheet and ILL. C. C. No. 17, Sheet Nos. 6-11, 17, 27, 28, 58, 124, 135.1. This tariff filing embodied a proposed general increase in gas service rates, and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of Title 83 of the Illinois Administrative Code (the "Code"), 83 Ill. Adm. Code Parts 285 and 286.

On July 31, 2012, The Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL") filed with the Commission, pursuant to Section 9-201 of the Act, the following revised tariff sheets: ILL. CC. No. 28, Title Sheet and ILL. C. C. No. 28, Sheet Nos. 4-10, 16, 18, 28, 29, 59, 130-140, 151.1. This tariff filing embodied a proposed general increase in gas service rates and revisions of other terms and conditions of service. The tariff filing was accompanied by direct testimony, other exhibits, and other materials required under Parts 285 and 286 of the Code.

Notices of the proposed tariff changes reflected in these rate filings were posted in North Shore's and Peoples Gas' (the "Utilities" or "Companies") business offices and published in secular newspapers of general circulation in the Utilities' respective service

areas, as evidenced by publishers' certificates, in accordance with the requirements of Section 9-201(a) of the Act and the provisions of 83 Ill. Adm. Code Part 255.

The Commission issued a Suspension Order for North Shore's tariff filing on September 6, 2012, which suspended the tariffs to and including December 27, 2012, and further initiated Docket 12-0511. On December 19, 2012, the Commission issued a Resuspension Order that suspended these tariffs to, and including, June 27, 2013.

The Commission issued a Suspension Order for Peoples Gas' tariff filing on September 6, 2012, which suspended the tariffs to and including December 27, 2012, and initiated Docket 12-0512. On December 19, 2012, the Commission issued a Resuspension Order that suspended these tariffs to, and including, June 27, 2013.

On September 24, 2012, the Administrative Law Judges ("ALJs") held an initial status hearing and, on the oral motion of Commission Staff ("Staff"), consolidated these cases and also orally approved a case schedule and data request response time schedule.

On September 26, 2012, North Shore and Peoples Gas each filed motions for protective orders in each Docket, pursuant to 83 Ill. Adm. Code §200.600.

On October 5, 2012, the Utilities filed a motion for entry of case management plan and schedule, pursuant to Section 10-101.1 of the Act and 83 Ill. Adm. Code §§ 200.190, 200.370, and 200.500.

On October 29, 2012, the ALJs issued a case management order.

On January 23, 2013, the Attorney General of the State of Illinois (the "Attorney General" or "AG") filed a motion to strike and deny Peoples Gas' and North Shore's request for a conditional SFV Tariff and certain associated testimony.

On January 29, 2013, the AG filed a motion to strike certain portions of the surrebuttal testimony of the Utilities' witnesses Mr. Hengtgen and Mr. Stabile.

On January 29, 2013, Staff filed a motion to strike certain portions of the surrebuttal testimony of the Utilities' witness Mr. Hoops.

On March 11, 2013, the Utilities filed a motion to correct the transcript of the February 4-8, 13, 2013 Hearings.

Rulings on motions are discussed further below.

Petitions to Intervene

Petitions to Intervene were filed or appearances were entered on behalf of the AG; the Citizens Utility Board ("CUB"); the City of Chicago (the "City") (collectively, CUB and the City are "CUB-City"); the Utility Workers Union of America, Local Union No. 18007 ("UWUA Local 18007"); and Interstate Gas Supply of Illinois, Inc. ("IGS Energy") (collectively, all of the foregoing parties are the "Intervenors"). All petitions were granted by the ALJs.

The Evidentiary Hearing

The evidentiary hearing was held February 4, 2013 through February 8, 2013, and February 13, 2013, at the offices of the Commission in Chicago, Illinois. At the evidentiary hearings, the Utilities, Staff, and the Intervenors entered appearances and presented testimony. The following witnesses testified on behalf of the Utilities: James F. Schott, Vice President and Chief Financial Officer, Integrys Energy Group, Inc., North Shore and Peoples Gas (NS Exhibit ("Ex.") 1.0 Revised ("REV"), PGL Ex. 1.0 REV., NS-PGL 22.0 Second Revised ("2REV"), NS-PGL Ex 37.0); Lisa J. Gast, Manager, Financial Planning and Analysis, Integrys Business Support, LLC (NS Ex. 2.0, PGL Ex. 2.0, NS-PGL Ex. 17.0, NS-PGL Ex. 23.0, NS-PGL Ex. 38.0); Paul R. Moul, Managing Consultant, P. Moul & Associates (NS Ex. 3.0, PGL Ex. 3.0, NS-PGL Ex 24.0 REV, NS-PGL Ex. 39.0); Kevin R. Kuse, Senior Load Forecaster, Integrys Business Support, LLC (NS Ex. 4.0, PGL Ex. 4.0, NS-PGL Ex. 40.0); Christine M. Gregor, Director, Operations Accounting, North Shore and Peoples Gas (NS Ex. 5.0 REV, PGL Ex. 5.0 REV, NS-PGL Ex. 16.0, NS-PGL Ex. 25.0, NS-PGL Ex. 41.0 Corrected ("CORR")); Sharon Moy, Rate Case Consultant, Regulatory Affairs, Integrys Business Support, LLC (NS Ex. 6.0, PGL Ex. 6.0, NS-PGL Ex. 18.0, NS-PGL Ex. 26.0, NS-PGL Ex. 42.0 REV); John Hengtgen, Consultant, Stafflogix Corporation (NS Ex. 7.0, PGL Ex. 7.0, NS-PGL Ex. 19.0, NS-PGL Ex. 27.0, NS-PGL Ex. 43.0); Kyle Hoops, General Manager, District Field Operations, The Peoples Gas Light and Coke Company (NS Ex. 8.0, PGL Ex. 8.0, NS-PGL Ex. 20.0, NS-PGL Ex. 28.0 REV, NS-PGL Ex. 40.0); Noreen E. Cleary, Assistant Vice President, Total Compensation, Integrys Energy Group, Inc. (NS Ex. 9.0, PGL Ex. 9.0, NS-PGL Ex. 29.0, NS-PGL Ex. 45.0); John P. Stabile, Tax Director, Integrys Business Support, LLC NS Ex. 10.0, PGL Ex. 10.0, NS-PGL Ex. 30.0 REV, NS-PGL Ex. 46.0); Christine M. Phillips, Manager, Benefits Accounting, Integrys Business Support, LLC (NS Ex. 11.0, PGL Ex. 11.0, NS-PGL Ex. 31.0, NS-PGL Ex. 47.0); Valerie H. Grace, Consultant, Stafflogix Corporation (NS Ex. 12.0 REV, PGL Ex. 12.0 REV, NS-PGL Ex. 32.0, NS-PGL Ex. 48.0 REV), Joylyn C. Hoffman-Malueg, Rate Case Consultant, Regulatory Affairs, Integrys Business Support, LLC (NS Ex. 13.0, PGL Ex. 13.0, NS-PGL Ex. 33.0); Philip M. Hayes, Director, Project Management, Integrys Business Support, LLC (PGL Ex. 14.0, NS-PGL Ex. 21.0, NS-PGL Ex. 34.0, NS-PGL Ex. 49.0 CORR); Thomas L. Puracchio, Manager, Gas Storage, Integrys Business Support, LLC (PGL Ex. 15.0, NS-PGL Ex. 35.0); and Debra E. Egelhoff, Manager, Gas Regulatory Policy, Integrys Business Support, LLC (NS-PGL Ex. 36.0, NS-PGL Ex. 50.0).

The following witnesses testified on behalf of Staff: Dianna Hathhorn, Accountant, Accounting Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 1.0, Ex. 11.0); Daniel Kahle, Accountant, Accounting Department Financial Analysis Division, Illinois Commerce Commission (Ex. 2.0, Ex. 12.0 REV, Ex. 23.0, Ex. 24.0); Mike Ostrander, Accountant, Accounting Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 3.0, Ex. 10.0, Ex. 13.0 REV, Ex. 25.0); Bonita Pearce, Accountant, Accounting Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 4.0, Ex. 14.0); Michael McNally, Senior Financial Analyst, Finance Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 5.0, Ex. 15.0); Brett Seagle, Gas Engineer, Engineering Department, Energy Division, Illinois Commerce Commission (Ex. 6.0, Ex. 16.0); Christopher Boggs, Rates Analyst, Rates Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 7.0); William Johnson, Economic Analyst, Rates Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 8.0, Ex. 17.0); Alicia Allen, Rate Analyst, Fates Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 9.0); David Rearden, Senior Economist, Policy Program, Energy Division, Illinois Commerce Commission (Ex. 18.0); Darin Burk, Pipeline Safety Program Manager, Safety and Reliability Division, Illinois Commerce Commission (Ex. 19.0); Philliph Buxton, Program Manager, Energy Engineering Program, Safety and Reliability Division, Illinois Commerce Commission (Ex. 20.0); David Sackett, Economic Analyst, Policy Program, Policy Division, Illinois Commerce Commission (Ex. 21.0); and Rochelle Phipps, Senior Financial Analyst, Finance Department, Financial Analysis Division, Illinois Commerce Commission (Ex. 22.0).

The Attorney General's witnesses were: Michael Brosch, Principal, Utilitech Inc. (AG Ex. 1.0, AG Ex. 4.0); David J. Effron, Consultant (AG Ex. 2.0, AG Ex. 5.0); and Scott Rubin, Consultant (AG Ex. 3.0 REV, AG Ex. 6.0).

CUB-City's witness was: Ralph Smith, Consultant (CUB-City Ex. 1.0, CUB-City Ex. 2.0).

The Utility Workers Union of America's witness was: Richard Passarelli, Business Manager, Local Union Number 18007, Utility Workers Union of America, AFL-CIO (UWUA Ex. 1.0).

Interstate Gas Supply of Illinois' witness was: Vincent A. Parisi, General Counsel, Interstate Gas Supply of Illinois, Inc. (IGS Energy Ex. 1.0, IGS Energy Ex. 2.0).

The above references to testimony are intended to include the attachments thereto, whether given separate exhibit numbers or not.

All parties were given the opportunity to cross-examine witnesses. On April 25, 2013, the ALJs marked the record "Heard and Taken".

Rulings on Motions

A status hearing was held on September 24, 2012, as stated above, where the ALJs granted Staff's motion to consolidate these Dockets.

On October 16, 2012, after considering all of the parties' arguments, the ALJs entered a Protective Order for these dockets.

On October 29, 2012, the ALJs granted the Utilities' Motion for Entry of an Order Regarding Case Management Plan and Schedule.

On December 13, 2012, the ALJs granted Staff's motion for leave to file supplemental rebuttal testimony of Mr. Ostrander.

On January 29, 2013, the ALJs granted Staff's motion for leave to file supplemental rebuttal testimony of Mr. Kahle.

During the evidentiary hearing on February 6, 2013, the ALJs denied both Staff's motion to strike portions of Utilities' witness Mr. Hoops' surrebuttal testimony and the AG's motion to strike and deny the Utilities' request for a conditional SFV tariff and certain associated testimony.

During the evidentiary hearing on February 7, 2013, the ALJs granted Staff's oral motion for leave for the parties to file surrebuttal testimony on the issue of Net Operating Loss Adjustments. The ALJs also denied the AG's motion to strike certain portions of the surrebuttal testimony of the Utilities' witnesses Mr. Hengtgen and Mr. Stabile during this hearing.

On March 13, 2013, the ALJs granted the Utilities' motion to correct the transcript of the Feb. 4-8, 13, 2013 Hearings.

On April 17, 2013, the Utilities filed a Motion to Admit Evidence on 2013 Debt Costs. On April 19, 2013, the AG filed a response indicating there was no objection to the motion. The ALJs granted the motion on April 24, 2013.

Post-Hearing Briefs

On March 8, 2013, the Utilities, Staff, the AG, CUB-City, and IGS Energy, each filed Initial Briefs ("Init. Br.").

On March 26, 2013, the Utilities, Staff, the AG, CUB-City, and IGS Energy each filed Reply Briefs ("Rep. Br.").

On March 28, 2013, per direction of the ALJs, the Utilities submitted a draft Proposed Order and Staff, the AG, CUB-City and IGS Energy submitted draft position statements.

On April 26, 2013, the ALJs issued their Proposed Order.

On _____ __, 2013, Briefs on Exceptions ("BOE") were filed by _____.

On _____ __, 2013, Reply Briefs on Exceptions ("RBOE") were filed by _____.

This Order considers all of the positions and arguments set out in the exceptions briefs and reply briefs on exceptions listed above.

B. Nature of Operations

North Shore

North Shore is engaged in the business of transporting, purchasing, storing, distributing and selling natural gas at retail to approximately 158,000 residential, commercial, and industrial customers within 54 communities in Lake and Cook Counties, Illinois. This service territory covers about 259 square miles. The company owns approximately 2,303 miles of gas distribution mains and approximately 96 miles of transmission lines. North Shore employed approximately 163 people at the time these cases were filed. North Shore is a wholly owned indirect subsidiary of Integrys Energy Group, Inc. ("Integrys"). NS Ex. 1.0 Rev. at 8.

Peoples Gas

Peoples Gas is engaged in the business of transporting, purchasing, storing, distributing and selling natural gas at retail to approximately 826,000 residential, commercial, and industrial customers within the City of Chicago. This service territory covers about 237 square miles and has a population of approximately three million people. The company owns approximately 4,119 miles of gas distribution mains and approximately 419 miles of transmission lines. Peoples Gas also owns a gas storage field, Manlove Field. Peoples Gas employed approximately 1,162 people at the time these cases were filed, nearly all within the City of Chicago. Peoples Gas is a wholly owned indirect subsidiary of Integrys. PGL Ex. 1.0 Rev. at 8-9.

II. TEST YEAR (UNCONTESTED)

The Utilities proposed calendar year 2013, the twelve months ending December 31, 2013, as the test year. NS Ex. 6.0 at 4-5; PGL Ex. 6.0 at 4-5. The 2013 test year data were based on the Utilities' forecasted 2013 revenues, expenses, and rate bases, subject to appropriate adjustments. The proposed test year is reasonable (NS Ex. 6.0 at 2; PGL Ex. 6.0 at 2), is uncontested, and is approved.

III. REVENUE REQUIREMENT

"Under long established federal and Illinois constitutional law, and Illinois ratemaking law, a utility's rates must be set so as to allow it the opportunity to obtain full recovery of its prudent and reasonable costs of service, including its costs of capital." *North Shore Gas Co., et al.*, ICC Docket Nos. 11-0280, 11-0281 Cons. (Order Jan. 10, 2012) ("*Peoples Gas 2011*") at 5. The legal standards governing a utility's right to a fair and reasonable rate of return, in particular, are well-established and familiar. A public utility has a constitutional right to a return that is "reasonably sufficient to assure confidence in the financial soundness of the utility and [is] adequate, under efficient and

economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Bluefield Water Works & Improvement Co. v. Public Service Comm'n of the State of West Virginia*, 262 U.S. 679, 693 (1923). The authorized return on equity "should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). The Commission "fully embraces the principles set forth" in the *Bluefield* and *Hope* cases. *In re Consumers Ill. Water Co.*, ICC Docket No. 03-0403 (Order April 13, 2004) at 41; *Peoples Gas 2011* Order at 5. Allowing a utility the opportunity to recover fully its costs of service, including its costs of capital, is in the long-term interests of customers, because this is necessary in order for the utility to be able to provide adequate, safe, and reliable service over time at the least long term cost. *Peoples Gas 2011* Order at 5.

The Commission, in a rate case, is required to set just and reasonable rates. 220 ILCS 5/9 201(c). The rates must be just and reasonable to the utility and its stockholders as well as customers. *Bus. and Prof. People for the Pub. Interest v. Illinois Commerce Comm'n*, 146 Ill. 2d 175, 208, 585 N.E.2d 1032, 1045 (1991).

The formula for determining a utility's costs of service -- its revenue requirement is well-established and uncontested. RR = OE + (ROR x RB). A utility's revenue requirement ("RR") equals: (1) its operating expenses ("OE") plus (2) a reasonable rate of return ("ROR") on its rate base ("RB"). *Commonwealth Edison Co. v. Illinois Commerce Comm'n*, 322 Ill. App. 3d 846, 849, 751 N.E.2d 196, 199 (2d Dist. 2001).

A. North Shore

North Shore's final proposed base rate revenue requirement is $85,703,000, or $87,313,000 if costs recovered as Other Revenues ($1,610,000) are included, and North Shore states that its proposed revenue requirement is just and reasonable based on the testimony and other exhibits in evidence. *E.g.,* NS-PGL Ex. 42.0 Rev. at 3; NS-PGL Ex. 42.1N, lines 1, 5, 10, and 11, col. [H].

At each of the direct, rebuttal, and surrebuttal testimony stages, each of the Utilities presented pie charts showing the drivers of their cost increases over the levels approved in the Utilities' 2011 rate cases (*Peoples Gas 2011*) and summary information regarding those drivers. NS-PGL Init. Br. at 10-13.

B. Peoples Gas

Peoples Gas' final proposed base rate revenue requirement is $628,894,000, or $645,089,000 if costs recovered as Other Revenues ($16,195,000) are included, and Peoples Gas states that its revenue requirement is just and reasonable based on the testimony and other exhibits in evidence. *E.g.,* NS-PGL Ex. 42.0 Rev. at 3; NS-PGL Ex. 42.1P, lines 1, 5, 10, and 11, col. [H].

As noted above, the Utilities' presented information on the drivers of their cost increases over the levels approved in *Peoples Gas 2011*.

IV. RATE BASE

A. Overview

Utilities

North Shore's surrebuttal presented a year-end rate base of $209,116,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part, certain updates, and the correction of certain prior calculation errors. NS-PGL Ex. 43.0 at 26; NS-PGL Ex. 43.1N at Sched. B-1; NS-PGL Ex. 43.2N at Sched. B-2. North Shore's Schedules also presented average rate bases for 2013 and for the last six months of 2013.

Peoples Gas' surrebuttal presented a year-end rate base of $1,659,271,000, reflecting adjustments proposed by Staff and intervenors that the utility agreed with or accepted in whole or in part, certain updates, and the correction of certain prior calculation errors. NS-PGL Ex. 43.0 at 26; NS-PGL Ex. 43.1P at Sched. B-1; NS-PGL Ex. 43.2P at Sched. B-2. Peoples Gas' Schedules also presented average rate bases for 2013 and for the last six months of 2013.

North Shore's and Peoples Gas' rate bases are supported by extensive, detailed evidence, including the testimony of John Hengtgen (overall rate base and the underlying calculations and supporting various components of rate base); Kyle Hoops (key components of Gross Utility Plant); Christine Gregor (the test year forecast, including the Capital Budget); Noreen Cleary (capitalized incentive compensation costs); Christine Phillips (updating the pension and OPEB liability figures and the pension assets/liability); and, as to Peoples Gas in particular, Thomas Puracchio (certain capital projects) and Philip Hayes (certain capital projects). NS-PGL Init. Br. at 14-15.

B. Uncontested Issues (All Subjects Relate <u>to NS and PGL Unless Otherwise Noted)</u>

1. Cushion Gas Calculation

The Utilities and Staff agree that a 3.0% estimate should be used in calculating cushion gas. PGL Ex. 15.0 at 8; Staff Ex. 6.0 at 30-31. This proposed estimate is not contested. Therefore, the Commission approves the 3.0% estimate and the cushion gas in rate base reflected in the rate base figures in this Order.

2. Plant

a. Forecasted Test Year Capital Additions – Utility Plant in Service (PGL)

Staff has withdrawn its proposed adjustment to Peoples Gas' rate base based on a comparison of budget to actual expenditures for three previous years. Staff Ex. 12.0 Rev. at 13. This is not contested. Therefore, the Commission approves Staff's withdrawal of this proposed adjustment to Peoples Gas' rate base.

b. Advanced Metering Infrastructure Project

The Utilities and Staff have agreed upon inclusion in rate base of the Advanced Metering Infrastructure Project. PGL Ex. 8.0 at 12; NS-PGL Ex. 28.0 Rev. at 8; Staff Ex. 6.0 at 16; Staff Ex. 16.0 at 6. This is not contested. Therefore, the Commission approves inclusion in rate base of the Advanced Metering Infrastructure Project.

c. LNG Control System Upgrade and Related Project

Peoples Gas has withdrawn the LNG Control System Upgrade project and the related project to construct a new control building from this rate case. NS-PGL Ex. 35.0 at 2-3. This is not contested. Therefore, the Commission approves the withdrawal of the LNG Control System Upgrade project and related project to construct a new control building from rate base.

d. Calumet System Upgrade

The Utilities and Staff have agreed upon inclusion in rate base of the Calumet System Upgrade Project. PGL Ex. 8.0 at 10; NS-PGL Ex. 28.0 Rev. at 9; NS-PGL Ex. 44.0 at 8; Staff Ex. 6.0 at 24; Staff Ex. 16.0 at 10; NS-PGL Cross Ex. 13. This is not contested. Therefore, the Commission approves inclusion in rate base of the Calumet System Upgrade Project.

e. CNG Fueling Station

Peoples Gas has withdrawn the CNG Fueling Station project from rate base. NS-PGL Ex. 44.0 at 2. This is not contested. Therefore, the Commission approves the withdrawal of the CNG Fueling Station project.

f. Incentive Compensation – Capitalized Amounts Disallowed in Prior Cases

Only for the purposes of narrowing the issues in this proceeding and without waiving any rights to contest such amounts in future proceedings, the Utilities do not object to removing the previously disallowed amounts related to incentive compensation from rate base. NS-PGL Ex. 27.0 at 4-5. This is not contested. Therefore, the Commission approves removing the previously disallowed amounts related to incentive compensation from rate base.

g. Original Cost Determination as to Plant Balances as of December 31, 2011

The Utilities and Staff agree that consistent with Part 510 of the Commission's rules, the Commission's order should state the following concerning the Original Cost Determination as to plant balances as of December 31, 2011:

> It is further ordered that the $3,016,429,000 original cost of plant for Peoples Gas at December 31, 2011, reflected on Peoples Gas' NS-PGL Ex. 27.14P, Line 19, Column B, is unconditionally approved as the original cost of plant. It is also ordered that the $424,299,000 original cost of plant for North Shore at December 31, 2011, reflected on North Shore's NS-PGL Ex. 24.14N, Line 17, Column B, is unconditionally approved as the original cost of plant.

NS-PGL Ex. 27.0 at 36; Staff Ex. 12.0 Rev. at 26-27. This is not disputed. Therefore, the Commission approves the above proposed language concerning the Original Cost Determination as to plant balances as of December 31, 2011.

3. Budget Plan Balances

The Utilities and the AG have agreed to a methodology for determining budget plan balances. NS-PGL Ex. 27.0 at 13-14; NS-PGL Ex. 43.0 at 4; AG Ex. 2.0 at 13; AG Ex. 5.0 at 3-4. This is not disputed. Therefore, the Commission approves the methodology for determining budget plan balances and approves the balances reflected in the rate base figures in this Order.

4. Accumulated Deferred Income Taxes – 50/50 Sharing Related to Tax Accounting Method Change

The Utilities are withdrawing their proposal for a 50/50 sharing with respect to a tax accounting method change related to the capitalization of certain types of indirect and overhead charges. NS-PGL Ex. 30.0 Rev. at 16. This is not disputed. Therefore, the Commission approves the withdrawal of the Utilities' proposal for a 50/50 sharing with respect to a tax accounting method change.

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

1. Year End Rate Base or Average Rate Base

Utilities

The Commission is charged with establishing just and reasonable rates for utilities, their stockholders, and their customers. Rates must be set so as to allow the utility the opportunity to obtain full recovery of its prudent and reasonable costs of service. NS-PGL Init. Br. at 2-3. In the instant case, the Commission must decide if the year end rate base methodology proposed by the Utilities or the average rate base methodology proposed by Staff, the AG, and CUB-City is more appropriate.

The Utilities submit that the evidence demonstrates that a year end rate base calculation is more appropriate than the average rate base methodology proposed by Staff, the AG, and CUB-City, on the specific facts of the instant cases.

The average versus year end rate base issue is a critical issue, because it has a very large impact on the Utilities' ability to recover the costs of plant investments, including Peoples Gas' Accelerated Main Replacement Program ("AMRP"). The Commission's prior findings in the Utilities' 2009 rate cases, *North Shore Gas Co., et al.*, ICC Docket Nos. 09-0166, 09-0167 Cons. (Order Jan. 21, 2010) ("*Peoples Gas 2009*"), *aff'd in part and rev'd in part*, *People ex rel. Madigan v. Illinois Commerce Comm'n*, 2011 IL App (1st) 100654, 958 N.E.2d 405 (2011), *appeal denied*, 963 N.E.2d 246 (Ill. 2012), and the testimony of the Utilities and of Local Union No. 18007, Utility Workers Union of America, AFL CIO ("Union Local 18007") in the instant cases, have established, without refutation, that the AMRP has numerous important benefits for customers and has created hundreds of jobs. The Commission previously has found that the long-term benefits of the AMRP include, among other things, enhancements of reliability and safety, significant long-term reductions in operating expenses, and, as to customers served by the legacy low pressure system, the ability to use more energy efficient appliances and equipment. *Peoples Gas 2009* Order at 164-173. The Utilities and the Union, moreover, submitted evidence of the AMRP's benefits, which no witness challenged. *E.g.,* PGL Ex. 14.0 at 4, 7-8; Union Local 18007 Ex. 1.0 at 2. The AMRP also involves a new apprentice training program and 500 highly skilled jobs that are at risk if the AMRP is put at risk, including hundreds of union jobs. NS-PGL Ex.22.0 2nd Rev. at 7; Union Local 18007 Ex. 1.0 (entire).

The plant investment cost recovery reductions under the average rate base method that is advocated by Staff, the AG, and CUB-City are very large.

- Per Staff's revised calculations in its Initial Brief, the average rate base method will reduce Peoples Gas' gross plant in rate base by $151,242,000, including $61,402,000 of "AMRP investment costs. Staff Init. Br., App. B at 6, col. (c), line 1 (*citing* Staff Ex. 12.0 Rev., Sched. 12.01P Rev., col. (C), line 4); Staff Ex. 12.0 Rev., Sched. 12.07P Rev. at 2, col. (D), line 8.
- When all impacts are taken into account, per Staff's calculations, the average rate base method would reduce Peoples Gas' rate base by $98,890,000. Staff Init. Br., App. B at 6, col. (c), line 23. The Utilities note that Staff's calculations for this adjustment use data from Peoples Gas' rebuttal exhibits even though the starting point for Staff Initial Brief App. B is Peoples Gas' surrebuttal rate base. The calculations should be based on Peoples Gas' surrebuttal exhibit NS-PGL Ex. 43.1P, page 1 of 2, by comparing column (F) to column (H). Based on that comparison, the Staff average rate base adjustment would reduce rate base by $95,687,000 (col. (H), line 15, less col. (F), line 15, or the difference between $1,563,584,000 and $1,659,271,000).

- Per Staff's calculations, the average rate base method will reduce North Shore's gross plant in rate base by $11,235,000. Staff Init. Br., App. A at 6, col. (c), line 1.
- When all impacts are taken into account, per Staff's calculations, the average rate base method would reduce North Shore's rate base by $5,353,000. Staff Init. Br., App. A at 6, col. (c), line 23. The Utilities note that Staff's calculations for this adjustment use data from North Shore's rebuttal exhibits even though the starting point for Staff Initial Brief App. A is North Shore's surrebuttal rate base. The calculations should be based on North Shore's surrebuttal exhibit NS-PGL Ex. 43.1N, page 1 of 2, by comparing column (F) to column (H). Based on that comparison the adjustment would reduce rate base by $4,176,000 (col. (H), line 15, less col. F, line 15, or the difference between $204,940,000 and $209,116,000).

The AG and CUB-City's average rate base calculations are similar to those of Staff.

While the use of the average rate base methodology will not instantly end the program, the AMRP is not sustainable over time absent timely and adequate cost recovery. NS-PGL Init. Br. at 5-6; *see also, e.g.,* Tr. at 442–445. The Staff, AG, and CUB-City positions are not grounded in a real world assessment.

The Utilities have advocated use of a year end rate base calculation in these Dockets on the grounds, in brief, that:

(1) the Commission's rules (83 Ill. Adm. Code § 285.2005(e)) permit use of a year end rate base in a future test year rate case;
(2) the rates being set in these cases will not go into effect until July 2013, which means that the Utilities will experience the revenue impact of any rate increase for at most half of 2013; and
(3) use of a year end calculation will result in setting rates that better match the Utilities' cost of service during the period in which the rates will be in effect and come closer to giving them the opportunity to recover fully their costs of service.

E.g., PGL Ex. 1.0 Rev. at 13; NS Ex. 1.0 Rev. at 11-2; PGL Ex. 7.0 at 4-6; NS Ex. 7.0 at 4-5; NS-PGL Ex. 22.0 2nd Rev. at 7-10; NS-PGL Ex. 27.0 at 5-9. The Utilities also presented the alternative of a calculation as of September 30, 2013, the midpoint of the last six months of the year, which reflects the logic of the Staff and intervenor position discussed below but also takes into account the fact that the rates being set will not go into effect until the second half of 2013. NS-PGL Ex. 43.0 at 10-11; NS-PGL Ex. 43.1N at 2; NS PGL Ex. 43.1P at 2.

The Utilities' points (1), (2), and (3), above, are not really disputed. As to the Utilities' point (1), Staff witness Mr. Kahle's direct testimony noted that 83 Ill. Adm. Code § 285.2005(e) does not expressly state that year end rate base is permitted, but he also acknowledged that the rule indicated average rate base was not the only permitted

method. *See* Staff Ex. 2.0 at 9-10. Mr. Kahle agreed, during cross-examination, that the Commission's rules do not prohibit use of year end rate base in a future test year case. Tr. at 167. Intervenors also did not deny that the Commission's rules permit use of a year end rate base here.

As to the Utilities' point (2), neither Staff nor any intervenor denied that the rates being set in these cases will not go into effect until July, and, as a result, that the Utilities will experience the revenue impact of any rate increase for at most half of 2013. The Utilities' existing rates are based on a forecasted 2012 test year (*Peoples Gas 2011* Order at 5), and thus their rates in effect for the first half of the year will not include any recovery of the plant investment costs incurred by the Utilities in that period. Staff witness Mr. Kahle agreed the rates being set will become effective around July 1, 2013. Staff Ex. 2.0 at 5.

As to the Utilities' point (3), Staff, the AG, and CUB-City essentially shrug off that point, on the theory that it is irrelevant. For example, Staff witness Mr. Kahle acknowledged that the Utilities have increasing levels of plant investment, but he asserted that this was "normal" and that past Commission Orders, including the Orders in the Utilities' 2009 and 2011 future test year rate cases, approved use of the average rate base method. Staff Ex. 2.0 at 10-11. The Utilities did not propose end of year rate base, however, in their 2009 and 2011 cases. They did so in the instant Dockets because of changed circumstances, in particular, the timing of when the rates being set will go into effect and the loss of their infrastructure cost recovery rider due to an appellate decision. *E.g*., NS-PGL Ex. 27.0 at 6. Moreover, Staff elsewhere argues for proposed adjustments on the ground that they better match costs during the period when rates will be in effect. *See* Staff Init. Br. at 49, 68.

Staff, the AG, and CUB-City in the aggregate present two "matching" arguments and one related theoretical argument in support of use of the average rate base method in all future test year rate cases: (1) the use of the average rate base method better matches the costs of plant investments in the test year; (2) the use of the average rate base method better matches the determination of expenses in the test year; and (3) a future test year is sufficiently forward looking that there is no need to use the end of year method to reduce regulatory lag. None of those points warrants their proposal.

Their first point is limited to calculating costs as such as if a utility had perfect rates, or a reconciliation process, that allows it to exactly capture its costs incurred during the test year. That concept takes no account, however, of when the rates being set will go into effect, and thus of whether use of the average rate base will result in rates that give the opportunity to recover fully its costs of service. Indeed, CUB-City are emphatic that the matching principle they invoke is about calculation of costs and is separate from analysis of rates. *See* CUB-City Init. Br. at 13-15. Use of the average rate base method here would result in rates that under-recover costs, as discussed above.

The second point of Staff, the AG, and CUB-City is wrong. Their proposal is not actually a calculation of any sort relating to revenues, it is just about costs. *E.g.,* Tr. at

156-164; CUB-City Init. Br. at 13-15. In any event, revenues and expenses generally are measured on a cumulative basis as of December 31st of the test year. *See, e.g.,* combination of PGL Ex. 6.1, Sched. C-1, and PGL Ex. 5.1, Sched. C-4; *see also* Tr. at 157- 158. That is not an average. The AG suggests that Utilities witness Mr. Schott on cross examination agreed that depreciation expense is calculated on an average basis (AG Init. Br. at 10), but the cross examination was based on the presentation in a particular document in Peoples Gas' Part 285 filing. Depreciation expense is calculated on a cumulative basis as of December 31st of the test year in the Utilities' revenue requirements. *See, e.g*., PGL Ex. 5.1, Sched. C-4 at 1, col. [C], line 9 (forecasted depreciation expense figure of $90,903,000 as of December 31, 2013); PGL Ex. 6.1, Sched. C-1, line 24 (using that figure in the revenue requirement). The AG and CUB-City point to the Utilities' use of an average to calculate the cost of long-term debt (AG Init. Br. at 12; CUB-City Init. Br. at 14, 15), but that is a net income item, not an operating expense item, and the issues are distinct and the Utilities' calculation of that item is proper under 83 Ill. Adm. Code § 285.4000(b). NS-PGL Init. Br. at 134-136. CUB-City throws in the assertion that the Utilities' proposal is based on "matching rates with costs from outside the test year" (CUB-City Init. Br. at 14), but that assertion is unexplained and has no supporting citation. The end of year figures, by definition, are from the test year.

Staff and the AG argue that use of a future test year is sufficiently "forward looking", although the AG is inconsistent about whether this results in regulatory lag. *See* Staff Init. Br. at 12; AG Init. Br. at 13,14, 15, 17,18. That method does cause lag, as discussed above. That Staff and AG conceptual argument again disregards the facts regarding how the method would affect the sufficiency of cost recovery here. Staff witness Mr. Kahle testified in part that revenues should equal the rate base investment of the test year plus the expenses of the test year. Tr. at 156. That can only occur if rates are set such that they yield revenues matching those costs. The AG argues that end of year rate base is used in historical test year rate cases because it is more representative of the investment that the Utilities will have in their rate bases at the time that the rates go into effect. AG Init. Br. at 10. The AG once again is ignoring the facts regarding when the rates will go into effect here.

Staff and the AG deny that the average rate base method "disallows" any costs, but that is semantics and in any event it is incorrect. Costs are incurred to build plant, including the time value of the capital used to pay for the plant investment, plus, once plant goes into service, depreciation expense. For example, when a new meter is installed on January 5th, the utility has paid for the meter, and it starts to depreciate, even if it is not in the rate base used to set existing rates. *E.g*., Tr. at 158–159. With new rates not going into effect until July 2013, customers will not start paying any of the costs of those investments until up to six months after they are made. *E.g*., Tr. at 166–167. The average rate base method never makes up for the cost recovery foregone during that period when, as here, the new rates do not go into effect until the second half of the year, and Staff and the AG do not and cannot point to any means by which those costs ever will be recovered.

Staff and intervenors argue that under the end of year method, when the rates being set go into effect, they will reflect plant investment costs not to be incurred until the second half of 2013. *E.g.,* Staff Ex. 2.0 at 5. However, that argument does not change the reality of what the average rate base method means for cost recovery in the instant cases. Moreover, the Staff and intervenor argument has at least three other flaws. First, this is a future year rate case. Thus, there is nothing inherently inappropriate about rates that include future costs, as long as the utility complies with the future test year selection rule, 83 Ill. Adm. Code § 287.20(b). In this instance, the Utilities, under the rule, could have selected a future test year ending as late as July 31, 2014, 24 months from the tariff filing date, 83 Ill. Adm. Code § 287.20(b), although as a practical matter preparing and filing a test year that is not the calendar year or the utility's fiscal year is difficult. NS-PGL Ex. 22.0 2nd Rev. at 8-9. Indeed, if the test year were a future test year ending July 31, 2014, use of the average rate base method would yield a rate base that approximates a rate base as of January 31, 2014, which is one month further out in time than the year end rate base that the Utilities propose. NS-PGL Ex. 43.0 at 6.

Second, that Staff and intervenor point applies as a conceptual matter to the average rate base method, too. The average they advocate is the average of the amounts as of December 31st of the prior year and December 31st of the test year. So, the average also includes in its computation the costs of plant investment in the second half of the test year, although it cuts in half the recovery of those costs.

Third, the flip side of Staff and intervenor point is that, as to costs of plant investments in the first half of the year, customers will not start paying any of the costs of those investments until up to six months after they are made (*e.g.,* Tr. at 166–167), and the average rate base method never makes up for the cost recovery foregone during that period when, as here, the new rates do not go into effect until the second half of the year, as discussed above.

Staff, the AG, and CUB-City cites past Commission Orders approving the average rate base method in future test year rate cases, but that discussion cannot change what the evidence in the record shows about whether in these cases, use of a year end rate base calculation or an average rate base calculation is more appropriate in order to establish just and reasonable rates. The Commission, in meeting its duty to set just and reasonable rates, must base its decision exclusively on the applicable law and the evidence in the record here. 220 ILCS 5/10 103; 220 ILCS 5/10 201(e)(iv)(A).

The Utilities are not arguing that the past Commissions Orders on this subject are irrelevant. Past Commission Orders involving similar issues and evidentiary records generally are relevant, absent a change in law. However, in only two of the past Commission Orders that Staff and intervenors cite was the question of average versus end of year rate base contested: the 1990 Central Illinois Public Service Company rate case, *Central Illinois Public Service Co*., ICC Docket No. 90-0072, 1990 Ill. PUC Lexis 625 (Order Nov. 28, 1990) ("*CIPS*"); and Nicor Gas Company's 2004 rate case, *Northern Illinois Gas Co*., ICC Docket No. 04-0779 (Order Sept. 20, 2005) ("Nicor 2004"). *See also* Tr. at 167 (Staff witness Mr. Kahle acknowledging that the issue was

not disputed in the other past Commission Orders that Staff and Intervenors cite). The *CIPS* decision expressly stated that the question was "a close issue". *CIPS*, 1990 Ill. PUC Lexis 625 at *6. Moreover, the *Nicor 2004* decision expressly stated that the *CIPS* decision was not dispositive, and that subsequent cases where the issue was not contested contributed little to the analysis. "However, the above quoted language cited from 90-0072 does not clearly state a general rule. Instead, it addresses the question for that case, finds it to be a close issue, and ultimately decides in favor of the average rate base. Subsequent cases, in which this issue was not litigated, contribute little toward this discussion." *Nicor 2004* Order at 7.

Staff and intervenors are right that the *Nicor 2004* decision, in particular, does provide support for their argument for use of an average rate base calculation, but that past Order is not dispositive and the same result should not be reached here. The reality here is that, because the rates being set will not go into effect until July 2013, using the average rate base method would mean that the Utilities would under recover their 2013 plant investment costs in 2013, and the rates set here would not match the costs of service in the period in which they will be in effect as well as would rates set using a year end rate base. The Commission found against Nicor Gas, but the Utilities contend that the Commission should choose here the method that the evidence shows is most appropriate to set just and reasonable rates, which is the end of year method. Finally, the *Nicor 2004* decision did not involve any alternative, such as the September 30, 2013, alternative raised here by the Utilities.

The AG also discusses the four recent Orders in the Ameren and ComEd electric formula rate cases. AG Init. Br. at 9. Those Orders do not support use of the average rate base method here, and, if anything, do the opposite. There, the Commission agreed that, when setting rates, the end of year rate base method should be used. *E.g., Commonwealth Edison Co*., ICC Docket No. 11-0721 (Order May 29, 2012) at 17-18. The Commission decided to use the average rate base method only in reconciling the revenue requirement used to set rates for the "rate year", *i.e.*, the year in which the rates were in effect, with actual costs of the rate year. *Id*. at 18. The Utilities, in contrast, have no means to reconcile the revenue requirements being set in the instant cases with the actual costs they will incur in the period in which the rates being set are in effect.

The Utilities legally could have chosen a future test year with a later ending date, as late as July 31, 2014, 24 months from the tariff filing date. (83 Ill. Adm. Code § 287.20(b)), but as a practical matter, preparing and filing a test year that is not the calendar year or the utility's fiscal year is difficult. NS-PGL Ex. 22.0 2nd Rev. at 8-9. Staff identified only one utility, Illinois American Water Co., which has filed recent rates cases with test years other than its fiscal year. Staff Ex. 12.0 Rev. at 11. Even more importantly, in any event, the fact that the Utilities could have chosen a test year with a later ending date is not a reason to reach a wrong decision in the rates cases that they did file. The right decision here is use of the end of year method.

The Commission has a duty to set rates that are just and reasonable and allow the utility the opportunity to recover fully its costs of service. The Commission should approve use of the year end rate base method on the facts of the instant cases.

In the alternative, the Utilities propose that a calculation based on a rate base as of September 30, 2013, the midpoint of the last six months of the year, should be used. This alternative is a compromise as it recognizes concerns of Staff, the AG, and CUB-City, but it also recognizes when the rates being set will go into effect. *See* NS-PGL Ex. 43.0 at 10-11; NS-PGL Ex. 43.1N at 2; NS-PGL Ex. 43.1P at 2.

Staff, the AG, and CUB-City complain about the timing of the alternative proposal, but their complaints lack merit. The alternative calculation was proper surrebuttal and its component figures were provided in NS-PGL Ex. 43.1N at 2, and NS-PGL Ex. 43.1P at 2. Discovery was allowed and occurred with respect to surrebuttal. Staff and intervenors point to no related fact that needed to but could not be developed in discovery or at the hearing. Moreover, Staff, the AG, and CUB-City are inconsistent. They accepted surrebuttal revisions with new calculations by the Utilities that reduced rate base based on the availability of "bonus depreciation" in 2013 under the American Taxpayer Relief Act of 2012 (the "fiscal cliff" legislation, enacted January 2, 2013). *See* Section IV.C.6.c of this Order. Staff also accepted an alternative proposal of the Utilities in surrebuttal for a new calculation of pass-through taxes in determining cash working capital. *See* Section IV.C.3.a of this Order. The compromise proposal is more than fair, because it only reduces, but does not eliminate, the under-recovery of the Utilities' costs.

Staff

The Commission should adopt Staff's adjustments to compute rate base on an average methodology, since Staff's method takes into account that investments are made throughout the test year, rather than the Companies' method of a year-end rate base which inappropriately assumes, for rate setting purposes, that all investments are made at the beginning of the test year. Staff Ex. 12.0R, Scheds. 12.01 N and P Rev. The Companies chose a future test year ending December 31, 2013. An average rate base derives rates that properly match test year revenues and expenses which will occur throughout 2013 with the level of rate base investment also occurring throughout the year. A year-end rate base would derive revenues and expenses for 2013 which represent a level of investment that would not exist until the end of 2013. Staff Ex. 2.0 at 4-5.

A test year is a time period used to develop costs representative of the first year in which rates being set will be in effect. *Id*. at 4. Under the Commission's rules, utilities may select a historical test year or a future test year. (83 Ill Adm. Code 287.20) As far as Staff is aware, the Commission has only approved the use of a year-end rate base with a historical test year and has rejected proposals to use a year-end rate base with a future test year. Staff Ex. 2.0 at 6-8. The Companies selected a future test year which is already forward looking in that it largely relies upon projected costs. Staff Ex. 2.0 at 4.

The Companies argue that a year-end rate base is necessary to provide for adequate recovery of plant investments made throughout a future test year. NS-PGL Ex. 27.0 at 6. This flawed argument is based on the likely effective date of the tariffs rather than on the measurement of a test year's rate base. Staff's adjustments to compute rate base on an average methodology provide the proper rate base for the test year.

The Companies further argue that an increasing level of investments justifies the use of a year-end rate base. PGL Ex. 7.0 at 6; PGL Ex. 7.2; NS Ex. 7.0 at 5 and NS Ex. 7.2. An increasing level of investments, however, is the norm rather than the exception. Staff Ex. 2.0 at 10-11. Under cross examination, the Companies' witness Mr. James F. Schott admitted that one would usually expect continuing increases to plant investments and rate base following a test year. Tr. at 405-406. Furthermore, the Commission has considered this argument in prior rate cases and found that an increasing level of investments did not justify the use of a year-end rate base with a future test year. Staff Ex. 12.0 at 6-7. Should the Companies make additional significant investments beyond the future test year; however, the Companies can file new rate cases in order to recover the costs of projected investments occurring after the future test year. In fact, the Companies are already required to file biennial rate cases in 2014 and 2016 per Section 9-74 220(h-1) of the Act. Staff Ex. 12.0 at 4. The Companies will, again, have the choice of the most appropriate test year for their investment levels in such rate filings. Further, the Companies have not addressed why an average rate base is appropriate for North Shore, since it does not have the significant plant investment needs of the Peoples Gas accelerated main replacement program. *Id*.

The Companies also argue that the likely effective date of the tariffs justifies the use of a year-end rate base. PGL Ex. 1.0 at 3; NS Ex. 1.0 at 3; PGL 7.0 at 4; NS 7.0 at 4. The Companies, however, could have selected a future test year with an ending date as far out as July 31, 2014. Instead, the Companies chose a future test year ending December 31, 2013. Mr. Schott testified that, in making the decision to use a future test year ending December 31, 2013, the Companies did not make an estimate of the cost of preparing forecasts for a non-calendar year test period; did not quantify the monetary affect of using a calendar test year that would not align the test period and the period rates were in effect; and did not perform a cost benefit calculation to determine if preparing a test year that aligned with the period rates were in effect was worth the effort. Tr. at 440-441. Company witness John Hengtgen testified that the test year chosen by the Companies is not representative of the time that rates will be in effect and that the representative test year is 2014. Tr. at 592-593. Thus, the Companies' year-end rate base proposal appears to be an attempt to correct a poorly chosen test year with an improperly measured rate base. Any perceived disadvantage from this choice that the Companies alone made should not now be cause for the Commission to adopt an improperly measured rate base that is inconsistent with Commission practice. As Mr. Schott testified, the Commission does not ensure that a utility recover its costs based on the relation of the end of a test year and the date rates take effect. Further, as Mr. Schott testified, the Companies will not be denied recovery of plant investments in excess of the estimated average investment amounts included in rate base as the Companies may seek to have all such incremental investments included in rate base in future rate cases. Tr. at 414-415.

Staff's position is consistent with recent rate cases in which the Commission approved an average rate base with a future test year: Docket No. 08-0363, Northern Illinois Gas Company (filed June 4, 2008); Docket No. 09-0319, Illinois-American Water Company, (filed July 8, 2009); Docket No. 11-0282, Ameren Illinois Company (filed March 23, 2011); Docket No. 11-0767, Illinois-American Water Company (filed December 7, 2011); Docket Nos. 11-0280/0281 (filed February 15, 2011) and Docket Nos. 09-0166/0167 (filed February 25, 2009). Staff Ex. 2.0 at 8. Docket Nos. 11-0280/0281 and Docket Nos. 09-0166/0167 are the Companies' most recent rate cases. Staff's position is also consistent with that of the AG and CUB-City who also propose that an average rate base be used in this proceeding. AG Ex. 1.0 at 10-13; AG Ex. 2.0 at 4-8; CUB-City Ex. 1.0 at 13-17.

The Companies argue that "the facts of this case compared to that of the Utilities' last two rate cases certainly are different and therefore is [sic] relevant." NS-PGL Ex. 43 at 6. Again, these facts – the timing of the rate filing, effective date of new rates, and level of proposed investment – were known to the Companies and subject to their own decisions for the test year period. The Commission's practice with respect to average rate base for future test periods is well established, and the Companies have not demonstrated sufficient justification to break this long-standing precedent.

The Companies made a belated alternative proposal to use an "average" rate base as of September 30, 2013. Since this alternative proposal was introduced in the Companies' surrebuttal testimony, Staff has not had the opportunity to seriously consider or investigate this alternative proposal due to time constraints. The alternative proposal unsurprisingly results in a rate base amount that is closer to the Companies' year-end rate base proposal than the proper average rate base for the test year. No party has filed testimony in support of this alternative proposal, not even Mr. Hengtgen who offered the proposal. Tr. at 587. This late offered alternative has not been properly vetted in this proceeding and should not be seriously considered as a valid option.

AG

As noted by AG witness Michael Brosch, the Companies' proposed test year employs forecasted 2013 rate base, capital structure and operating income amounts. However, the Companies' filings are not internally consistent because they include both average and year-end information in a manner that distorts and overstates the asserted revenue requirement. The Companies' proposed rate base is forecasted at year-end as of December 31, 2013, while the balance of the test year revenue requirement calculations, including revenues, operations and maintenance ("O&M") expenses and cost of debt, utilizes forecasted average data expected to be experienced throughout calendar year 2013. AG Ex. 1.0 at 6.

The Companies have proposed the use of a hybrid test year approach, using forecasted operating revenues and O&M expenses throughout the 2013 test year that have not been annualized at year-end, while proposing a year-end rate base including net plant investment that is forecasted to exist at year-end. This approach significantly increases the test year 2013 revenue requirement, while destroying the balance that is

normally required in test year regulation, where all elements of rate base and operating income are matched and made to be internally consistent.

Both AG witnessess Brosch and David Effron recommend that an average rate base be employed in setting the Companies' rates, so as to match the average income statement and cost of capital calculations that are employed while not overstating the revenue requirement expected to be incurred in the 2013 test year. Staff witness Daniel Kahle and CUB witness Ralph Smith likewise endorsed the use of an average rate base methodology to ensure that the Companies' revenues match its actual costs.

The Companies attempt to justify their proposed hybrid test year approach using year-end rate base in an otherwise average test year by citing "several reasons" for this approach:

1. The rates being set in this proceeding will not go into effect until well into the test year, most likely not until sometime in July 2013 and will likely be in effect until sometime in 2015.

2. The Companies are permitted under the Commission's rules to use a year-end rate base.

3. The Companies have been and continue to increase their investment in plant in service to better serve their customers.

PGL Ex. 7.0 at 4; NS Ex. 7.0 at 4. Aside from these arguments, the Companies' only quantitative analysis is offered in support of the third argument, where in PGL/NS Exhibits 7.2, historical balances of "Gross and Net Plant" are summarized to show how such amounts have changed historically.

The reasons offered by the Companies for the unorthodox proposal to incorporate year-end rate base values in a future test year are hardly persuasive. First, an assumed effective date of new gas rates from these proceedings in mid-2013 does *not* support adoption of year-end rate base. Between rate case orders, all the elements of the revenue requirement are subject to change and can be expected to change. It is impossible to accurately predict how the timing of new rates becoming effective will impact a utility's earnings. If future revenue or cost variances from the test year 2013 amounts that are used to set rates are favorable, the Company's earnings are likely to exceed authorized levels. Conversely, if such financial variances are negative, earned returns may be lower than authorized levels. When a future test year is employed to set rates, the potential for earnings attrition is minimized because the forecasted financial data upon which rates are based is not dated. Stated differently, there is minimal regulatory lag when a future/forecasted test year is employed. AG Ex. 1.0 at 11-12. Under these circumstances, it is not reasonable to select only one element of the ratemaking equation, in this case the rate base amounts, and presume such amounts

should be mismatched to the rest of the test year just in order to ensure that revenue requirements and potential future earnings are maximized.

Second, neither the Companies nor Mr. Hentgen provided any quantification of either historical or projected earnings attrition to justify mismatching the forecasted test year by using average income statement and cost of capital amounts with year-end rate base. In response to Data Requests DGK 7.06 and DGK 7.07, NS and PGL admitted that the only analysis performed in support of using the year-end versus average rate base position was presented in its direct filing in this case by Mr. Hentgen in comparing historical levels of Gross and Net Plant in Service. AG Ex. 1.0 at 12.

Likewise, historical trends in "Gross and Net Plant" quantified in PGL and NS Exhibits 7.2 do not reveal either historical earnings attrition or future expected earnings attrition that might justify using a year-end rate base. As noted by Mr. Brosch, the utilities' total revenue requirement is driven by more than just changes in Gross Plant in Service and Accumulated Depreciation. Operating income is a function of sales and revenue levels and each category of labor and non-labor expense. Rate base investment levels are driven by changes in Net Plant in Service as well as changes in Accumulated Deferred Income Taxes ("ADIT"), gas in storage and other working capital elements. In the present economic environment, declining interest rates have created a setting in which long term debt can be refinanced to yield significant savings that reduce revenue requirements. Mr. Hentgen's single-issue analysis focused on historical changes in Gross and Net Plant in Service does not address the multitude of other issues that impact revenue requirements. It is therefore essential that a proper matching of the elements of the revenue requirement be maintained to ensure that just and reasonable rates are approved by the Commission.

AG witness Effron concurred with these observations. First, he noted that it is unorthodox to use a year end rate base in conjunction with a future test year. Mr. Effron testified that it has been the consistent practice to use an average rate base when a future test year has been used to determine a regulated utility company's revenue requirements. For example, in each of the Companies' two most recent rate cases, (Docket Nos. 09-0166 and 11-0280 for North Shore and Docket Nos. 09-0167 and 11-0281 for PGL) a future test year was used to determine the revenue requirements, and in all cases, the future test year rate base was an average rate base. The same is true for the most recent cases filed by Ameren Illinois Company (Docket Nos. 11-0279 and 11-0282), and Nicor Gas Company (Docket No. 08-0363).

He noted that there are significant reasons why it is the usual practice to use an average rate base in conjunction with a future test year. First, the average rate base measures the net investment in facilities to provide utility service over the course of the year, rather than as of a point in time as of the end of the year. It is internally consistent with the measurement of expenses, billing determinants, and income over the course of the year. That is, using an average rate base properly matches the calculation of rate base with the other elements of the Company's revenue requirement and income in a given year. The return on rate base is a component of the total revenue requirement,

just as expenses such as salaries and wages, depreciation, and property taxes are. This component of the total revenue requirement, the return requirement, is calculated by multiplying the Company's cost rate of capital by its rate base. This converts the cost rate into a dollar cost, just as depreciation expense is calculated by multiplying the applicable depreciation rate by the relevant depreciable plant. AG Ex. 2.0 at 5-6.

When a unit of plant is put into service in December of a given year, the Company does not incur a capital cost on that plant for the whole year any more than it incurs depreciation expense on that plant for the whole year or any more than it incurs a year of payroll expense for an employee hired in December. The Company's annual revenue requirement does not include a full year of capital cost on plant that is put into service at the end of the year. The issue of how to correctly recognize the value of the rate base when assessing a utility's capital costs has been closely analyzed by the Commission in no less than four recent cases: ICC Docket Nos. 11-0721, 12-0321, 12-0001 and12-0293. As the Commission noted in Docket No. 11-0721, using a utility company's "rate base as of December 31st of any year assumes that its investment in plant is the same on January 1st (and thereafter) of that year as it is on December 31st of that year. That clearly cannot be the case." Order, May 29, 2012, at 19.

The use of the average rate base to calculate the return requirement included in the revenue requirement is similar to calculating the return requirement for the year by calculating the return requirement for each of the twelve months and then summing those monthly return requirements. The return on the average rate base represents the actual dollar cost of capital incurred by the Company over the course of the year, and that is what is included in the Company's total revenue requirement. AG Ex. 2.0 at 6-7. It should be noted, too, that NS-PGL witness Schott confirmed during cross-examination that the Companies calculation test year depreciation expense for both companies using an averaging methodology – not an end of year basis. Tr. at 403-404.

The rate base is sometimes calculated as of the end of the test year (except for those elements of rate base that fluctuate or are seasonal in nature, such as storage gas inventory) when a historic test year is used to determine a utility company's revenue requirement. Generally speaking, a historic test year is a period consisting of twelve months of actual data, with that twelve month period ending at a point in time before the record in the rate case being processed closes. The theory supporting the use of an end of test year rate base in these circumstances is that the rate base as of the end of the test year is more representative of the investment that the utility will have in its rate base at the time that the rates being set go into effect. AG Ex. 2.0 at 7.

The circumstances present in a historical test year environment that point to the use of an end of year rate base, however, are not present in this case. The Companies have selected to use a future test year, not a historic test year, to develop their revenue requirements. Consistent with the use of a future test year, the rate bases should reflect average balances, not end of year balances, for the major components. *Id.* at 7-8.

Mr. Effron calculated the AG-proposed adjustment to the Companies' rate bases to reflect an average rate base and updated the figures in his rebuttal testimony. The effect is to reduce the North Shore test year rate base by $5,353,000 (AG Ex. 5.1, Schedule DJE-1N) and the PGL rate base by $98,886,000 (AG Ex. 5.1, Schedule DJE-1P). They should be adopted by the Commission.

In their rebuttal and surrebuttal testimony, the Companies offer various arguments in support of their unorthodox request to calculate a future test year rate base using end of year values. NS-PGL witness James Schott's rebuttal testimony characterizes use of the average rate base by Staff and intervenor witnesses as substantial "reductions in the Utilities' recovery of the costs of plant investments." He states that Mr. Effron's proposal to use an average test year rate base, rather than an end-of-test year rate base, reduces the Peoples Gas rate base by $151,958,000 and the North Shore rate base by $11,083,000. NS-PGL Ex. 22.0 at 5. But this criticism is an invalid one.

The adjustments in Mr. Effron's direct testimony to reflect an average rate reduced the Peoples Gas rate base by $86,798,000 and the North Shore rate base by $5,974,000. The numbers initially cited by Mr. Schott are reductions to estimated test year plant, not rate base. He later acknowledged in his Surrebuttal testimony that those fingures failed to recognize that the reductions to the plant balances are partially offset by reductions to accumulated depreciation and accumulated deferred income taxes ("ADIT"). NS-PGL Ex. 37.0 at 8.

Both Mr. Schott and Mr. Hengtgen attempt to justify the use of a year end rate base in this case on the grounds that the rates will not go into effect until July 2013, although the future test year begins in January 2013. But the Commission previously addressed whether the use of a year end rate base would be appropriate in similar circumstances. In his direct testimony, Staff Witness Kahle noted that in Docket No. 04-0779, Northern Illinois Gas Company ("Nicor") proposed a future test year with a year-end rate base, but that the Commission rejected this approach, finding that an average rate base "better matches the level of rate base during the test year with the revenues and expenses during the test year." Staff Ex. 2.0 at 7-8. Nicor filed that case in November 2004, with a future test year consisting of the twelve months ending December 31, 2005 and the rates set to go into effect in October 2005. In other words, in Docket No. 04-0779, the new rates did not go into effect until approximately ten months after the beginning of the future test year. Yet the Commission found that an average rate base was appropriate (while use of a year-end rate was not) in those circumstances. If the use of an average rate base was appropriate in Docket No. 04-0779, it is certainly appropriate in the present case. AG Ex. 5.0 at 2-3.

Contrary to the Companies' claims, the use of an average rate base methodology in no way denies the Utilities recovery of a substantial part of their 2013 costs. An average rate base affords a reasonable opportunity for the Companies to recover the overall costs incurred to provide service. An average rate base, when used with a forecasted or future test year, properly matches the level of investment throughout the year with the related levels of sales, revenues, operating expenses, depreciation expenses, taxes and cost of capital that have been measured on an average, rather than year-end, basis of accounting.

For example, the Utilities' cost of debt capital is expected to decline at the dates of each scheduled long term debt refinancing, but both PGL and NS have calculated and used an average cost of debt throughout the test year, rather than annualizing the lower long term debt costs expected to exist at year-end. AG Ex. 4.0 at 6-7.

It is fundamentally unfair to ratepayers for the Companies to recover a higher cost of long term debt using average test year costs and then assert an entitlement to year-end rate base investment levels that are expected to be higher than average levels. As explained in Mr. Brosch's direct testimony, it is important to maintain a matched and internally consistent methodology in calculating test year revenue requirement to avoid distorting and overstating the revenue requirement.

Mr. Schott's assertion that approval of an average rate base approach would "reduce dramatically the Utilities' investments allowed in rate base, especially Peoples Gas' Accelerated Main Replacement Program ("AMRP") projects" is particularly misguided. NS-PGL Ex. 22.0 at 6. As explained by Mr. Brosch, there is no disallowance of any actual investments caused by utilization of an average rate base. Mr. Schott has identified no actual investments that have actually been made by the Utilities and that are excluded from rate base under the AG's proposals. He confirmed, too, during cross-examination that is it the Company's position that it is *not* Peoples Gas' position that it could not afford to continue investing in its AMRP if the Commission uses an average rate base in the Company's rate cases. Tr. at 415.

What is "reduced" in the AG's filing is the Companies' intended overstatement of rate base that is caused by projecting plant additions further into the future than the balance of the other operating income and capital structure inputs to the test year revenue requirement calculation. Separate adjustments to PGL's rate base associated with PGL's projected CWIP amounts proposed by Mr. Effron are unrelated to the need for the Commission to calculate the Companies' rate base using average plant figures, rather than year-end amounts. AG Ex. 4.0 at 7.

Moreover, the ability to employ a forecasted test year offers the considerable advantage to the Utilities of being able to include in their rates estimated costs for planned new investments that represent costs not yet incurred. Thus, the average versus year-end rate base dispute involves no actual costs that have been incurred by the Utilities', but instead involves only a question of how far into the future we include speculative estimates of future investments that have only been budgeted by the Utilities. In contrast, if an historical rate base were employed, ratepayers would be assured of paying a return on only actual, incurred levels of plant investment, rather than uncertain estimates of future investments that are only planned to be made. In this sense, use of an average rate base reduces the risk to ratepayers of overstating the estimates of future investments that are expected to be made in the forecasted test year. The bottom line is that utilization of forecasted levels of rate base and expenses results in minimal regulatory lag to the considerable advantage of utility investors. AG Ex. 4.0 at 7-8.

The Companies' claim that they will be denied an opportunity to earn a return on all of their prudently invested capital that is used to construct new utility plant under the AG's proposed continuation of average rate base methodologies is particularly specious. The continuous capital spending incurred by the Companies is common throughout the gas utility industry and results in the continuous addition of new utility plant assets that are long-lived. New plant assets that are acquired or constructed by the Utilities will be includable in rate base for decades into the future. When PGL and NS add new plant investments that cumulatively exceed the estimated average investment amounts included in rate base by the AG, the Companies will retain the opportunity and can be expected to seek rate base inclusion for all such incremental investments in many future rate cases during the decades that new plant remains in service. There is no permanent loss of return on investment in new plant because all new investments in long-lived plant assets are recorded on the Utilities' books and can be included in rate base within all future test years while the plant remains in service. *Id.* at 8-9.

Likewise, there is no disallowance of plant investment when new plant is added between test years, or in this case, when new plant is forecasted to be added that eventually exceeds the calculated average of forecasted test year investment levels. Ratemaking need not continuously capture growth in rate base to produce a reasonable opportunity to earn a fair return on investment. It is essential to maintain a balanced approach that quantifies all elements of the revenue requirement in an internally consistent manner. It's important to note that the AG-proposed adjustment to utilize the average rate base approach that was used in this and in previous PGL/NS rate cases is a measurement convention, rather than any disallowance of new rate base investments. The Companies' estimated plant investments that are expected to be in service throughout the 2013 test year have been measured at an average level, based upon estimated costs without disallowances, so as to properly match the rate base with the corresponding measurement period for operating revenues, operating expenses and the estimated cost of capital – nothing more, nothing less.

Mr. Schott also argues that if the new rates in this case go into effect in July 2013, use of an average rate base deny would deny recovery of higher rate base investments that may exist by year-end 2013. NS-PGL Ex. 22.0 at 8. Mr. Schott is wrong. If new rates are effective in July, based upon an average rate base for 2013, the Company will immediately commence recovery of a return on investment for the amounts of estimated rate base investments that are in place at that date, since July is near the mid-point of calendar year 2013. This is entirely appropriate because the test year estimated expense and revenue levels at this mid-point of the calendar year should also be reasonably synchronized with the newly implemented rates. The fallacy with Mr. Schott's argument is the supposition that use of a forecasted test year somehow entitles the Companies to an expectation of zero regulatory lag throughout and after the 2013 test year. AG Ex. 4.0 at 9-10.

On the other hand, assuming new rates go into effect until July 2013, utilization of a year-end rate base, as proposed by the Companies, would produce a windfall for

the Companies. Using a forecasted year-end rate base would cause the new rates effective in July of 2013 to be overstated, because such rates would include a return on forecasted rate base plant assets that do not yet exist at that time. In particular, the forecasted plant investments expected by the Companies to be added in the last half of 2013 that exceed average projected rate base levels, would represent non-existent Plant as of July that are not being used in the provision of public utility services as of July of 2013. AG Ex. 4.0 at 10.

Mr. Schott also complains that the rates being set will not reflect higher levels of investment after 2013. NS-PGL Ex. 22.0 at 9-10. But this criticism is an equally invalid one. All of the elements of the Companies' revenue requirement are dynamic throughout the passage of time. After 2013, it is reasonable to assume that PGL's gross investment level in new plant will continue to grow, as emphasized by Mr. Schott. However, after 2013, the Companies' continuing accruals of depreciation expense will produce higher accumulated depreciation reserve balances that reduce rate base. After 2013, the full annual impact of long term debt refinancing activities will be recorded as reduced interest expense. After 2013, continuing changes in gas sales volumes, employee staffing levels, wage rates, revised actuarially determined pension expenses, and expense savings from new technologies or efficiency gains would all impact the Companies' revenue requirements. Bonus tax depreciation has now been extended through 2013 and will contribute to rapidly growing accumulated deferred income tax balances that reduce rate base. Finally, some of the investments in new plant for the PGL Accelerated Main Replacement Program are expected to produce significant expense savings that should be captured in future rate case test years, but are not reflected in 2013 test year expenses. AG Ex. 4.0 at 11. Mr. Schott's criticism ignores all of these facts.

As for the claim that AMRP investment will be negatively impacted, the Companies have offered no evidence that use of a forecasted test year with an average rate base will cause any deterioration in credit ratings or reduce the Companies' access to capital on reasonable terms. Mr. Schott's testimony instead indicates a "reduced willingness" to invest. In response to Data Request AG 16.01a, PGL stated, "Mr. Schott's testimony speaks for itself. That being said, Mr. Schott's testimony indicates a reduced willingness by management to invest in accelerated main replacement in the circumstances of the reductions in recovery of the costs of such projects proposed by Staff, the AG, and CUB-City." AG Ex. 4.0 at 12-13; AG Ex. 4.3. The same response clarifies that public safety will not be jeopardized by any reduced discretionary investments made by PGL if traditional average rate base calculations are used in the forecasted test year, by indicating, "The Utilities maintain a safe and reliable system. They have never claimed that accelerated main replacement is necessary to avoid significant reductions in safety and reliability."

For his part, Company witness Hengtgen acknowledges that a future test year, as employed by the Utilities, would typically be based upon a simple average of the rate base amounts at December 31, 2012 and December 31, 2013, as reflected in the AG-proposed revenue requirement calculation. Mr. Hentgen states at page 8 of his

Rebuttal that, "First, I agree that the test year chosen by the Utilities is future in nature and is for calendar year 2013. I also agree that the proposal of an average rate base would typically be a simple average of the rate base amounts at December 31, 2012, and December 31, 2013." NS-PGL Ex. 27.0 at 8. Moreover, Mr. Hengtgen recognizes no difference in the regulatory lag that arises from using a future test year as compared to an historical test year. For instance, he fails to note that with an historical test year, the utility must first make the capital investments in new utility plant and then seek recovery only after the investments have been made. This entails considerably more regulatory lag than a future test year, where new utility rates are set based upon estimates of future capital spending. As noted above, under these circumstances, when relying on historical test year data, this Commission and many others around the country routinely allow use of a year-end rate base, with annualized revenue and cost adjustments at year-end, in an effort to reduce the regulatory lag arising from ratemaking that requires actual spending prior to rate recovery.

Mr. Hengtgen also makes note in his Rebuttal that while the Commission has approved a year end rate base when historical test years are employed, "[t]he matching principal as formulated by Staff and these intervenors is not applied in those situations to require an average rate base." NS-PGL Ex. 27.0 at 8. But what Mr. Hengtgen fails to recognize is that the vast reduction in regulatory lag that occurs when using a future test year eliminates any need to modify the matching principle to the year-end rate base approach that is often employed when using an historical test year. AG Ex. 4.0 at 14.

In his surrebuttal testimony, Mr. Hengtgen offered for the first time, what he characterized as "an attempted compromise", an alternative that calculates a September 30, 2013 rate base amount for the Commission to consider. NS-PGL Ex. 43.0 at 10. This so-called compromise introduces an entirely new set of rate base numbers not previously filed by the Utilities, including new Plant Additions, accumulated depreciation, deferred income taxes and all the other elements of the new, alternative rate base. This eleventh-hour compromise of sorts should be rejected by the Commission. While moving the previously proposed December 31 end of year forecasted numbers forward by three months, it still fails to provide an equitable representation of the average plant investment (and other rate base element) values that better reflect the Company's actual capital costs in the test year.

For all of these reasons, the Companies proposal to employ a year-end rate base in the calculation of the revenue requirement in this case should be rejected, and Mr. Effron's adjustments to reflect an average rate base for both the PGL and NS rate bases, as detailed in AG Ex. 5.1, Schedules DJE-1P and DJE-1N, should be adopted.

CUB-City

CUB-City aver that NS-PGL has departed from its own past positions and the Commission's consistent practice by proposing a future test year that incorporates year-

end rate base and accumulated depreciation costs.[1] CUB-City Ex. 1.0 at 14; NS-PGL Ex. 43.0 at 7; Tr. at 412. CUB-City also opposed the Companies "compromise" position advanced in surrebuttal testimony, to boost the average year rate base by using "75 percent of the change from the beginning of the year the end of the year, which would approximate a September 30th average." Tr. at 583-584.

CUB-City argue that each of the Companies' proposals would discard the Commission's established practice (in future test year cases) of measuring those capital costs based on an average rate base for the test period. CUB-City Ex. 1.0 at 13, 15. CUB-City note the Companies ask that the Commission and ratepayers make up for the Companies' refusal to match its test year to the period for which the Companies want rates to cover costs. In effect, CUB-City aver, the Companies ask to be indemnified against any economic consequences of their presumptuous inaction.

CUB-City recommend that the Commission reject the Companies' proposals. CUB-City argue NS-PGL have not provided a reason to change the Commission's reasonable, well-established practice. Moreover, CUB-City maintain, the proposed change would unlawfully fail to reflect the manifest weight of the record evidence. CUB-City argue the Companies rely on speculation about post-test year costs that are not in this record, to inflate the costs defined by test year rules. *Business & Professional People in the Public Interest v. Illinois Commerce Comm. ("BPI I")*, 136 Ill. 2d 192, 225-227 (1989); 83 Ill. Adm. Code Part 287. The resulting rates, say CUB-City, would not be lawful, just and reasonable, or supported by the evidence of record. 220 ILCS 5/9-201(c); 220 ILCS 5/10-103.

a. The Evidence Does Not Warrant a Change in the Commission's Rules or Its Consistent Practice, and Disregarding Those Rules Would Be Unlawful

CUB-City aver the Companies' proposal to use a year-end rate base with its future test year discards a clearly understood, long-standing Commission practice. *See* NS-PGL Ex. 43.0 at 7 ("I never argued against the proposition that traditionally in Illinois rate cases when a future test year is selected, an average rate base is used.") In the numerous future test year cases identified by CUB-City expert Ralph Smith, none have used a year-end rate base to anticipate alleged post-test year cost changes. CUB-City Ex. 1.0 at 15. CUB-City note the Companies have not identified a single instance where the Commission has combined a future test year with a year-end rate base. CUB-City Ex. 1.0 at 5, 8. CUB-City maintain the Companies' approach represents a "radical departure from traditional ratemaking in Illinois," and the Companies have provided no evidence that warrants such a change in Commission policy. CUB-City Ex. 1.0 at 15.

First, CUB-City note, the Companies admit that the average rate base is the more accurate measure of their actual test year costs. Their expert witness expressly confirmed this conclusion of the various Staff and intervenor experts. Tr. at 577. In

[1] CUB-City's references to a year-end or average rate base are intended to include other costs affected by the rate base determination.

fact, state CUB-City, the Companies' expert, John Hengtgen, expressly distinguishes the year-end rate base he proposes for ratemaking from an average rate base, which is representative of the capital costs the Companies actually incur during their selected test year. Tr. at 594. He also confirmed that the Commission's practice of using an average rate base recognizes the gradual change in capital costs a utility actually incurs over the course of a test period. Tr. at 596.

Second, CUB-City aver, an average rate base is the only measure of test year investment that appropriately matches the elements of the revenue requirement including rate base, revenues and operating expenses. CUB-City Ex. 1.0 at 16. Mr. Smith explained:

> Information for 2013 net operating income is largely based upon the Company's budgeted/forecast results over that 12-month period. Thus, the net operating income reflects an average test year concept. Similarly, the future test year rate base should also reflect the 2013 future test year average (rather than just a one-day point as of the end of the future test year). The use of average future test year rate base properly matches the 12 month period used for determining net operating income with the 12-month period used for rate base.

CUB-City note AG witness Brosch confirms this test year matching principle:

> An average rate base, when used with a forecasted or future test year, properly matches the level of investment throughout the year with the related levels of sales, revenues, operating expenses, depreciation expenses, taxes and cost of capital that have been measured on an average, rather than year-end, basis of accounting.

AG Ex. 4.0 at 6. Moreover, CUB-City state, the Commission is required to follow its own rules, which incorporate this test year matching requirement. *BPI I*, 136 Ill. 2d 192, 219; *also* 83 Ill. Adm. Code Part 287. Lawful rates must be based on the test year data, not the Companies' speculation about future rate base costs.

Third, CUB-City aver, the Companies' main complaint is one about rates, not test year costs. CUB-City argue the Companies improperly confuse the <u>cost</u>-focused matching principle of test year ratemaking with their desire to have <u>rates</u> match costs from beyond the test year. The matching principle recognized in the Commission's rules and Illinois law is not the match the Companies seek. CUB-City maintain the test year matching principle mandates cost and revenue data from a <u>common</u> test period. CUB-City Ex. 2.0 at 10.

> The test-year rule prevents a utility from mismatching revenues and expenses. The utility cannot use a low revenue figure from one year and a high expense figure from another year to bolster its evidence in support of a rate increase. In turn, the Commission decides what test year would be most appropriate and bases its rate decisions on the test-year data.

BPI I, 136 Ill. 2d 192, 219; *also* 83 Ill. Adm. Code Part 287.

CUB-City note the Companies' expert presumes to define the principle differently. Mr. Hengtgen contends that "[t]he matching principle . . . is somewhat intertwined with the rate effectiveness timing issue." NS-PGL Ex. 43.0 at 5. CUB-City aver that despite the clear requirement for data from a common period, the Companies have made a novel (and improper) proposal to match test year rates with costs from outside the test year. In any case, the record does not contain the costs the Companies want to use instead of test year data. Their request, CUB-City say, is for the Commission to base its determination on costs that are not in the record.

CUB-City argue that Mr. Hengtgen attempted to maintain this self-serving confusion of rates and costs in his oral testimony. *See* Tr. at 586-588. CUB-City note that Staff witness Daniel Kahle rejected the Companies' distortion of the matching principle, correctly pointing out that "[t]he match refers to the test year," not to extra-test year periods. Tr. at 155. CUB-City state the Companies readily abandoned that distorted "principle" when a different approach promised to increase their revenue requirement. "[B]oth PGL and NSG have calculated and used an average cost of debt throughout the test year, rather than annualizing the lower long term debt costs expected to exist at year-end." AG Ex. 4.0 at 6. CUB-City further note that AG witness Michael Brosch also noted the fundamental unfairness to ratepayers of using a higher cost of long term debt (based on average test year costs), while simultaneously claiming a year-end rate base investment, because it is higher than an average rate base.

Finally, CUB-City aver, there is no need or justification for Commission consideration of un-quantified speculation about costs from a period beyond the future test year the Companies selected. The Commission's rules allow utilities to file rate cases using a test period that ends as much as 24 months beyond the date of filing, latitude that tests the limits of non-speculative forecasting. In addition, utilities can file another rate case at any time its rates diverge significantly from its costs.

CUB-City note that the Commission previously has considered the circumstances and arguments the Companies present in this case. CUB-City argue the Commission's determination there is wholly applicable to this case.

> The Company selected a forecasted, future test year that already reflects the Company's increasing investment on a forward-looking basis relative to when the Company filed its

> case. As Staff noted, the Commission gives utilities sufficient flexibility to make their rate cases forward looking. In light of the forward looking test year selected by the Company, the facts in this case do not support using a year-end rate base with a future test year. The average rate base proposed by Staff more accurately reflects the cost of service for the test year because it better matches the level of rate base during the test year with the revenues and expenses during the test year. The Commission finds that the average rate base proposed by Staff is more appropriate than the year-end rate base proposed by the Company, given the future test year selected by the Company.

Staff Ex. 12.0 at 6-7, *quoting* Order, Docket No. 04-0779 of September 20, 2005 at 8.

b. The Companies' Alleged Cost Recovery Problems Are the Result of Their Own Decisions and Inaction

CUB-City note that under the Commission's test year rules, PGL had a number of options for defining the cost basis of its proposed rates. Considering its options, PGL made a series of choices. CUB-City state that although the available options included a test year that coincided with the resulting period rates will be in effect, the Companies continued their practice of using a future test year instead of an historical test year. 83 Ill. Admin. Code 287.20, 287.30, 287.40, Tr. at 407. CUB-City aver NS-PGL also chose to use a calendar year instead of a different 12-month period. Ultimately, CUB-City state, the Companies chose to do what was convenient – use a calendar year test year; they declined the option to provide costs for the period rates will be in effect (June 2013 - May 2014).

CUB-City point out that at the time the decision to propose the 2013 calendar year as its future test year was made, the Companies knew that a rate case would be filed before a statutory deadline of August 2013. Tr. at 434. The Companies also were aware of the "real world consequences" of when rates go into effect -- consequences discussed by their senior management witness, Mr. Schott. NS-PGL Ex. 37.0 at 3, 6; Tr. at 434. In fact, CUB-City aver, the Companies acknowledge that a better aligned test year would obviate the problem PGL perceives as resulting from its selected test year. Tr. at 600-601. Nonetheless, CUB-City state, the Companies did not develop any estimate of the cost of preparing a special forecast for a non-calendar year test year that would better match the period about which they complain. Tr. at 440. They simply decided that it was too difficult, though they do not suggest that they were incapable of performing the task. Tr. at 444-446. They also chose not to develop an estimate of the financial consequences of using a misaligned test year (Tr. at 440) or a cost-benefit assessment comparing (a) use of a year-end rate base versus (b) use of an aligned test year and cost data. Tr. at 441; City Cross Ex. 2.

CUB-City point out that the Companies admit, "[i]n this instance, the Utilities, under the rule, could have selected a future test year ending as late as July 31, 2014, 24 months from the tariff filing date, 83 Ill. Adm. Code § 287.20(b) . . . ." NS–PGL Init. Br. at 23. The Companies go on to describe how they lawfully could have done precisely what they ask the Commission to do for them unlawfully.

> Indeed, if the test year were a future test year ending July 31, 2014, use of the average rate base method would yield a rate base that approximates a rate base as of January 31, 2014, which is one month further out in time than the year end rate base that the Utilities propose.

NS-PGL Init. Br. at 24.

CUB-City argue the Companies are attempting to compensate for their failure to present cost data for that post-test year period by having the Commission abandon its standard approach. Instead of using an average rate base in future test year cases, they propose the novel combination of a future test year and a year-end rate base. CUB-City aver that the Companies attempt to distinguish their earlier compliance with Commission practice (their 2009 and 2011 cases) by claiming that they proposed an end-of-year rate base approach in this case "because of changed circumstances, in particular, the timing of when the rates being set will go into effect and the loss of their infrastructure cost recovery rider." NS–PGL Init. Br. at 20. But those circumstances were known when the Companies selected their 2012 calendar year test period or did not affect the Companies' decision. CUB-City note the likely date when rates will become effective is easily determined from the utility's choice of filing date and the PUA's statutory suspension periods. *See* 220 ILCS 5/9-201(b). As to the rider, the Companies' senior management witness tried to explain the alleged connection, but he admitted that the 2013 appellate court decision voiding an unlawful rider did not actually affect their test year choice. Tr. at 444.

CUB-City note that the Companies made no attempt to address, before filing this case, problems they clearly anticipated. Instead, CUB-City state, it appears the Companies were content simply to ask for year-end rate base, even though the Companies also were aware that was more than the rules allow. Tr. at 441-442 ("We knew that would be an issue, yes.").

CUB-City argue the extraordinary accommodation the Companies request would allow them to avoid (a) any effort to match its test year with the period rates will be in effect, as well as (b) any economic consequences of their decision to ignore the available options that could lawfully support the requested relief.

CUB-City note that the Companies' Initial Brief acknowledges their unused opportunities to avoid the alleged mismatch between rates based on costs for the test year they chose and costs for their preferred (post-test year) cost period. CUB-City

argue that the Companies' arguments distort the test year matching principle in that allegation, the Companies' unused opportunities to mitigate the effects of a test year choice are significant. *See* CUB-City Init. Br. at 13. CUB-City aver the Commission's consideration of such utility failures in its ratemaking decisions is appropriate, and it has been sustained on appellate review. *See Ameren Illinois Co. v. Illinois Commerce Comm'n*, 2012 IL App (4th) 100962, ¶ 115 ("the utility bears some of the responsibility for the mismatch of these [test year and rate effective period rate base] amounts").

c. The Record Does Not Support a Year-End Rate Base

CUB-City aver that as a result of the Companies' decisions, the Commission is left with cost data from only one valid 12-month period to support rate changes in this case – calendar year 2013. Having refused to provide cost and revenue data for any other period, the Companies ask the Commission and ratepayers to compensate for their lack of effort and imprudent decision making. CUB-City point out that this record contains no post-test year costs that the Commission can lawfully use as a basis for cost-based delivery service rates. *See* 220 ILCS 5/16-108(c); 83 Ill. Adm. Code Part 287. CUB-City maintain that the Commission must reject the Companies' request for rates to recover out of test year costs.

CUB-City respond to the Companies' allegation that use of an average rate base would "dramatically reduce" their investment in utility infrastructure. NS-PGL Ex. 37.0 at 1. CUB-City state the evidence shows that any such reduction in needed investment would be the result of the Companies' management decisions, not of an inability to meet their statutory obligations. In the past, CUB-City note the Companies have gone years without filing a rate increase despite operating with "rates based on test year data that was years away from the times that the rates remained effective." Tr. at 599. Thus, say CUB-City , the new factor at work in this case is an expressed "reduced willingness" to invest, if the Commission accepts the intervenor recommendation that the Companies' revenue requirement be based on an average rate base. *See* AG Ex. 4.0 at 12; AG Ex. 4.3. CUB-City aver that unsupported claims of harm and implicit threats to the adequacy and reliability of regulated service do not enable a knowing departure from the Commission's rules and established practice.

> [T]he Companies could have selected a future test year with an ending date as far out as July 31, 2014. Instead the Companies chose a future test year ending December 31, 2013. Any perceived disadvantage from this choice that they alone made should not now be cause for the Commission to adopt an improperly measured rate base that is inconsistent with Commission practice.

Staff Ex. 12.0 at 5.

CUB-City aver the Commission cannot lawfully rely on the Companies' unsupported speculation about anticipated rate base changes to support the proposed rates. CUB-City maintain the Companies' proposal also is inconsistent with the Commission's test year rules and with the prohibition against single-issue ratemaking. CUB-City argue a decision approving those proposed rates could not be sustained on judicial review. *Business & Professional People in the Public Interest v. Illinois Commerce Comm.* ("*BPI I*"), 136 Ill. 2d 192, 219 (1989).

d. The Commission Should Approve CUB-City's Adjustments to Rate Base and Related Revenue Requirement Elements

CUB-City note that under the Act, a utility seeking a change in rates has the burden of proving with record evidence that its proposed rate changes are just and reasonable. 220 ILCS 5/9-201(c). Under the Commission's test year rules, the relevant costs are those for the utility's historical or future test year, and (with limited exceptions) rates are set to recover those costs. *See* 83 Ill. Adm. Code 287.40. CUB-City aver that the Companies propose to use a future test year and to provide costs for only that period, but then to adjust the resulting cost-based rates to recover costs for a different, post-test year period. NS–PGL Init. Br. at 17-18. CUB-City maintain that proposal is well outside the Commission's established practice and the record evidence does not support the Companies' proposal.

Failing to meet the PUA-mandated burden of proof, CUB-City point out that the Companies seek to shift responsibility for their desired outcomes to the Commission.

> [T]he Commission is required by law to establish just and reasonable rates; the rates must be just and reasonable to the utility and its stockholders as well as customers; and the rates must be set so as to allow the utility the opportunity to obtain full recovery of its prudent and reasonable costs of service.

NS-PGL Init. Brief at 17. CUB-City argue that this account of the ratemaking process, ignores the Companies' statutory duty to provide evidence to support their proposed rates. The Commission cannot lawfully ignore that lack of evidence, CUB-City state.

e. CUB-City Response to the Companies' Arguments

CUB-City respond to the three main arguments made by the Companies for their year-end rate base proposal:

> (1) the Commission's rules (83 Ill. Adm. Code § 285.2005(e)) permit use of a year end rate base in a future test year rate case;

> (2) the rates being set in these cases will not go into effect until July 2013, which means that the Utilities will experience the revenue impact of any rate increase for at most half of 2013; and
>
> (3) use of a year end calculation will result in setting rates that better match the Utilities' cost of service during the period in which the rates will be in effect and come closer to giving them the opportunity to recover fully their costs of service.
> NS-PGL Init. Br. at 19.

The Companies claim that "points (1), (2), and (3), above, are not really disputed." CUB-City maintain that claim is false. CUB-City note that under Illinois law, legal opinions and arguments are not proper subjects for testimony. *Bloomington v. Bloomington Township*, 233 Ill. App. 3d 724 (4th Dist. 1992), 735. Though the Commission exercises considerable flexibility in its application of that rule, the absence of legal argument in testimony does not mean that such issues are "not really disputed." In fact, CUB-City say, each of the Companies' arguments is unsupported by law and evidence; those assessments required the complete record being addressed in briefs.

NS-PGL Argument (1). CUB-City point out that the Commission filing rule that the Companies cite (83 Ill. Adm. Code § 285.2005(e)) is no more than that -- a filing requirement. That filing directive does not authorize a year-end rate base.

Moreover, CUB-City note that filing provision is inapposite to the Companies' specific post-test year proposal. While 285.2005(e) does not purport to bar unconventional rate base proposals in future test year cases, it requires more rigorous support for such proposals than is required for future test year costs based on an average rate base, say CUB-City. The rule requires 13 month-end balances of all rate base items, starting the month before the test year and continuing only through the end of the test year. 83 Ill. Adm. Code § 285.2005(e). CUB-City note that even that requirement for costs through the test year end would not provide the post-test year rate base costs needed to support the Companies' proposed rates.

NS-PGL Argument (2). The Companies complain that their rates will not go into effect until after the end of the test period they chose. CUB-City explain that any misalignment of the Companies' test year and the Companies' target cost period is a result of knowing choices the Companies made, with full awareness of the effects. CUB-City Init. Br. at 16-18.

NS-PGL Argument (3). The Companies contend that "use of a year end calculation will result in setting rates that better match the Utilities' cost of service during the period in which the rates will be in effect." CUB-City respond that this argument assumes, incorrectly, that the Commission is free to ignore its test year rules to accommodate the Companies' preference not to perform special forecasts for that period. The Commission is required to follow its own test year rules. *BPI I*, 136 Ill. 2d 192, 219. Also, say CUB-City, the argument falsely suggests the presence of record

evidence of the costs the Companies will incur during that post-test year period. CUB-City maintain that the Companies have offered only opinion that their rate base costs will be higher than test year costs (without quantification), and they have provided no information on revenue requirement elements other than a single issue, rate base.

CUB-City further respond to the Companies' descriptions of arguments of Staff and intervenor parties on the following points: (a) established Commission practice; (b) test year rules requirements; (c) unfairness of a year-end rate base (even if test year rules are ignored); and (d) the Companies' inconsistent positions on the appropriateness of an average year approach. CUB-City maintain that the Companies' responses miss the mark on each issue, and those points remain barriers to the unjustified and unlawful relief the Companies seek.

Commission Practice. CUB-City note that Companies' concession that no Commission decision has approved the approach they propose. NS-PGL Init. Br. at 22. CUB-City note that the Companies further acknowledge that only two cases even addressed the issue as a question of evidence. In each of those cases, the Commission decided against using a year-end rate base with a future test year.

Though CUB-City does not argue that past Commission orders are binding precedent, they maintain that Commission's actions in this case must be supported by substantial record evidence and must be adequately explained. 220 ILCS 5/10-201(iv)(A) and (iii). Where a decision diverges from an established past practice, a more compelling explanation is required. *People ex rel. Madigan v. Illinois Commerce Comm'n*, 2011 IL App(1st) 101776, ¶17. Here, say CUB-City, the only reason the Companies offer for their proposed divergence is self-interest. CUB-City argue that the Companies' requested change in the Commission's regular practice would shield the Companies from the foreseeable effects of their own management decisions. *See* CUB-City Init. Br. at 16-17. CUB-City maintain that a year-end rate base would allow the Companies to avoid the "difficult" (but not impossible or even impractical) task of aligning its objectives (recover costs for a particular future period) and their evidence (data for a different, less convenient test year). Tr. at 444-446. Granting the Companies' request would allow the Companies (at the same time) to avoid the predictable consequences of their deliberate inaction, say CUB-City.

Test Year Rules. CUB-City aver that the Companies' argument for a year-end rate base ignores the formidable legal obstacles to recovering costs from beyond its test year. CUB-City note that the Commission's test year rules require that rates be set on the basis of a utility's costs during a designated test period. Rates cannot be determined using costs from outside the test year. 83 Ill. Ad, Code Part 287; *BPI I*, 136 Ill. 2d 192, 219. Rates certainly cannot be determined on the basis of speculation about post-test year rate base costs that are never quantified, note CUB-City. 220 ILCS 5/10-103.

Without actual cost of service evidence for the Companies' target post-test year period, CUB-City argues the Commission cannot "establish the rates . . . which it shall

find to be just and reasonable." 220 ILCS 5/9-201(c). The Companies selected a test year and presented cost data for that period. They did not present needed, comprehensive revenue requirement elements for the post-test year period that is their focus. The Commission has no evidence of post-test year costs adequate to support a rate determination based on that period.

CUB-City further respond to the Companies' complaint that other parties maintain that "the revenue requirement should be based on the test year cost of service without regard to when the rates being set will go into effect." CUB-City explains that (with specific limited exceptions) is what the Commission's test year rules require, and why the rules allow utilities to propose an appropriate test year. 83 Ill. Adm. Code 287.40.

Alleged Unfairness. CUB-City avers that if the Commission concludes that, notwithstanding its test year rules, it is authorized to and must address the Companies' fairness arguments (NS–PGL Init. Br. at 21-22), those arguments still fail to establish a basis for the relief they request. The Companies claim that "[t]he Staff and intervenor focus here is on the test year costs, without regard to when the rates being set will go into effect . . . what they actually are analyzing in their proposal is only costs." NS–PGL Init. Br. at 25. CUB-City point out that argument is merely a restatement of the Companies' attempt to redefine the test year matching principle. *See* CUB-City Init. Br. at 13-14. "The test-year rule prevents a utility from mismatching revenues and expenses." *Commonwealth Edison Company v. Ill. Commerce Comm'n*, 405 Ill. App. 3d 389, 396 (1st Dist 2010), (2010), 219. Consistently, note CUB-City, the PUA requires that the components of the Companies' rate bases "must account for both increases and decreases (over a consistent period) at any point in time." *Id. at 405;* 220 ILCS 5/9-211. Thus, in addition to their misapplication of the matching principle to find a "mismatch" of costs and rates, CUB-City maintains the Companies' proposal also unlawfully mismatches test year costs defining the revenue requirement with <u>post</u>-test year rate base costs alone.

CUB-City maintain that the Companies had opportunities they chose not to take, and duties they chose not to perform. Instead, say CUB-City, the Companies now ask that the Commission unlawfully ignore its test year rules, as well as the lack of evidence of the post-test year costs they seek to recover. CUB-City avers that the Commission cannot lawfully approve the Companies' proposal for single-issue rate adjustments based on speculative, unquantified, post-test year changes in rate base.

CUB-City expert Smith recommends the following adjustments to the Companies' rate bases to reflect the Commission's standard practice of using an average rate base with a future test year. Adjusting North Shore's proposed rate base to the 2013 average projected levels reduces the Company's proposed rate base by $5.893 million. Adjusting Peoples' proposed rate base to the 2013 average projected levels reduces the Company's proposed rate base by $87.471 million. CUB-City Ex. 1.0 at 17. CUB-City argues the Commission should adopt adjustments to conform the proposed rate bases and revenue requirements to the Commission's test year rules and practice.

Commission Analysis and Conclusion

The Utilities argue that the Commission should adopt a year end rate base and Staff, AG and CUB-City argue that an average rate base should be used. The Commission has reviewed the evidence and its past decisions. The Commission finds that an average rate base methodology is more appropriate than a year end based calculation on the facts of the particular cases before us. The selection of an average rate base calculation take into account that investments are made throughout the test year, rather than the Companies' method of a year-end rate base which inappropriately assumes, for rate setting purposes, that all investments are made at the beginning of the test year. The Utilities chose a future test year ending December 31, 2013. An average rate base derives rates that properly match test year revenues and expenses which will occur throughout 2013 with the level of rate base investment also occurring throughout the year. A year-end rate base would derive revenues and expenses for 2013 which represent a level of investment that would not exist until the end of 2013. There have been no Commission decisions that have matched a year end based calculation with a future test year proposal. The Companies argue that a year-end rate base is necessary to provide for adequate recovery of plant investments made throughout a future test year. This position is based on the likely effective date of the tariffs rather than on the measurement of a test year's rate base. Staff's adjustments to compute rate base on an average methodology provide the proper rate base for the test year and is hereby adopted by the Commission.

While 285.2005(e) does not purport to bar unconventional rate base proposals in future test year cases, it requires more rigorous support for such proposals than is required for future test year costs based on an average rate base. The rule requires 13 month-end balances of all rate base items, starting the month before the test year and continuing only through the end of the test year. 83 Ill. Adm. Code § 285.2005(e).

The average rate base proposed by Staff more accurately reflects the cost of service for the test year because it better matches the level of rate base during the test year with the revenues and expenses during the test year. The Commission finds that the average rate base proposed by Staff is more appropriate than the year-end rate base proposed by the Company, given the future test year selected by the Company.

2. Plant

a. Forecasted Test Year Capital Additions – Utility Plant In Service (NS)

North Shore

North Shore presented extensive evidence supporting its Utility Plant in Service in rate base, as referenced in Section IV.A.1, *supra*. However, despite such evidence, North Shore states that Staff proposes an adjustment to reduce North Shore's forecasted additions to plant-in-service for the test year ending December 31, 2013, based on the historical spending pattern for budgeted capital expenditures for 2010,

2011 and 2012. Staff Ex. 23.0 at 2-3. Staff's adjustment is improper as it does not reflect North Shore's experience with public improvement projects. NS-PGL Ex. 28.0 Rev. at 4-5. The variance between North Shore's budget and actual expenditures is primarily due to public improvement projects, which have been rescheduled or delayed. These circumstances are not within North Shore's control. If the Commission determines that an adjustment is necessary, North Shore states that the last five years (2008 through 2012) would be more appropriate to determine the adjustment as it is more reflective of current spending patterns, particularly public improvement projects. NS-PGL Ex. 44.0 at 3. Further, a five-year period is a long enough period so that it does not inappropriately skew the average high or low based on an unusual year, such as 2009 data. North Shore cites the Commission's Order in *North Shore Gas Co., et al.*, ICC Docket Nos. 07-0241/0242 (cons.) (Order Feb. 5, 2008) ("*Peoples Gas 2007*") to support its proposal.

Staff

The Commission should reduce North Shore's forecasted test year capital additions to reflect a level that is likely to be spent based on the Company's historical spending pattern. The reduction is necessary to reflect the Company's inability or unwillingness to incorporate into its forecast an allowance for unforeseen changes that history has shown to result in less actual capital expenditures than budgeted. Staff Ex. 12.0 at 13; Staff Ex. 24.0, Sched. 24.02N.

The Company avers that projects are rescheduled or delayed due to factors beyond its control. NS-PGL Ex. 28.0 at 3-5. The Company further contends that its historical-based forecasting is accurate allowing for unforeseen external changes. NS-PGL Ex. 28.0 at 1. Rescheduled public improvement projects may be outside of North Shore's control, but that is irrelevant. An allowance for unforeseen external changes based on the Company's experience should be included in the development of its forecasts. The Company's argument merely demonstrates the well known fact that there is uncertainty and inaccuracy inherent in forecasting and budgeting for capital expenditures. The Company does not suggest that unforeseen events will not occur in the test year. Staff's proposal would adjust the Company's rate base to account for unforeseen changes based on a three-year average variance between the Company's actual and budgeted capital expenditure amounts.

The Company also takes issue with the use of the three-year average Staff uses to prepare an analysis of planned and actual spending. However, the recent three-year period best represents the Company's' current operations and provides a suitable basis on which to predict the Company's future capital spending. Staff witness Kahle used a three-year period for this type of analysis in two recent rate cases: Docket No. 09-0319 – IAWC and Docket Nos. 11-0280/0281 – the Companies' last rate proceeding. Both IAWC and the Companies accepted Staff's proposed adjustments. IAWC accepted Staff's adjustments for the purpose of that rate case. The Companies accepted Staff's adjustments in order to narrow the number of contested issues. Staff Ex. 12.0 at 15-16.

Commission Analysis and Conclusion

The Commission finds that North Shore's level of forecasted plant additions for the 2013 test year should be adjusted based on the budget to actual variance it has experienced in past years. Staff's proposed use of a three year period may not accurately reflect historical spending patterns. The Commission agrees with North Shore that by incorporating five years of data (2008-2012), it is more reflective of North Shore's actual experience. Therefore, North Shore's level of forecasted plant additions for 2013 should be adjusted based on a 5 year average.

b. Accelerated Main Replacement Program Projects (PGL)

People Gas

The Commission previously has found that Peoples Gas' Accelerated Main Replacement Program has long-term benefits that include, among other things, enhancements of reliability and safety, significant long-term reductions in operating expenses, and, as to customers served by the legacy low pressure system, the ability to use more energy efficient appliances and equipment. *Peoples Gas 2009* Order at 164-173. The Utilities and the Union, moreover, submitted evidence of the AMRP's benefits, which no witness challenged. *E.g.,* PGL Ex. 14.0 at 4, 7-8; Union Local 18007 Ex. 1.0 at 2. The AMRP also involves a new apprentice training program and 500 highly skilled jobs that are at risk if the AMRP is put at risk, including hundreds of union jobs. NS-PGL Ex.22.0 2nd Rev. at 7; Union Local 18007 Ex. 1.0 (entire).

Peoples Gas explains that in approving Rider ICR, the Commission acknowledged that Peoples Gas had submitted the AMRP plan with its surrebuttal testimony, which was filed on e-Docket on August 17, 2009. AMRP is a 20 year program to be completed by 2030. AMRP is designed to include a five-year ramp up period and a two-year ramp down period. NS-PGL 49.0 Corr. at 8. In fact, the Commission acknowledged Peoples Gas' ability to manage AMRP in Peoples Gas' 2009 rate case. *Peoples Gas 2009* Order at 195. Peoples Gas states that there are four main system upgrade goals for AMRP: (1) to retire 1,870 miles of cast iron/ductile iron gas distribution mains; (2) to upgrade approximately 300,000 service pipes; (3) to relocate gas meters from inside of customer facilities to outside; and (4) to upgrade the gas distribution system from low pressure to a medium pressure system. Further, to achieve the conversion of the gas distribution system to a medium pressure system, approximately 50 miles of new high pressure interstation main will have to be installed in total. NS-PGL 49.0 Corr. at 6. Since 2009, the following main replacement projects have been completed:

	2009	**2010**	**2011**	**2012**
New Gas Mains Installed (miles)	43	33	155	132
Old Mains	27	23	24	118

Retired (miles)				
Miles Restored	Not Available	Not Available	85.3	141.6
New Service Pipes	Not Available	Not Available	10,330	13,289
New Meter Regulator Sets	Not Available	Not Available	14,004	28,168
High Pressure Steel Interstation Main Installed (miles)	Not Available	Not Available	0.7	3.5

NS-PGL Ex. 49.0 Corr. at 7 – 8.

To achieve these results, Peoples Gas states that it engaged in extensive planning in 2010 and into 2011. Construction production has increased during the first two years of construction, namely 2011 (which was a partial year) and 2012 (the first full year of construction). The AMRP goal to schedule work to upgrade the distribution system is through the zonal approach as explained in the 2009 rate cases. The zonal approach targets geographic areas (neighborhoods) which allows efficiencies in design, permitting, and construction while minimizing disruption to the impacted customers and improved coordination with the City of Chicago. Peoples Gas' Five Year Construction White Paper documents the assumptions, attributes and inputs into analyzing and ultimately ranking the zones in terms of prioritizing system upgrades. The time frame for upgrades or the target period is broken down over the time frame 2013 to 2030. On page 18 of the White Paper, the first five year target period is 2013 to 2017 and the following detail is identified by year: neighborhood, total main retired, total number of services, and the number of vulnerable services. The intent of the Five Year Plan is to provide a road map of completing AMRP in the remaining years of the 20 year program.

Peoples Gas also explained the primary benefits of replacing the cast and ductile iron main are enhancing the safety and reliability of service for customers. Considering that the cast iron and ductile iron mains were installed between 50 and 150 years ago and the corrosion associated with cast iron pipes, it is necessary that they be replaced with plastic or cathodically protected steel main. The Commission recognized this in approving Rider ICR. *Peoples Gas 2009* Order at 170-173, 192-196. Not only are the new mains more reliable, but they also prevent ground water infiltration. The added benefits of accelerating this program include increased public safety for both Peoples Gas' customers and crews, construction and Operating and Maintenance cost savings, job creation, reduced environmental impact and increased functionalities with the higher pressure system. PGL Ex. 14.0 at 7-8.

Staff's Adjustments

Peoples Gas argues that Staff's adjustments to reduce rate base by $95.7 million for 2012 AMRP projects and $122.8 million for 2013 AMRP project costs are not only unsupported by the record but the adjustment "calculations" are seriously flawed. The

Utilities note that CUB-City may now be adopting these adjustments but offer no new arguments to save them. Peoples Gas not only demonstrated that it has met the scheduled work for 2012 and can reasonably forecast costs, but that it can prudently manage AMRP projects when unforeseen costs arise. Despite proposing these adjustments, Peoples Gas notes that at no time has Staff testified that these costs were not prudent, reasonable, or used and useful in providing customer service. If these punitive adjustments are approved, Peoples Gas argues that it will be unable to sustain its investments in AMRP resulting in a major loss for customers as well as in a loss of significant number of good-paying construction jobs that have already been created. NS-PGL Ex. 22.0 2nd Rev. at 2.

Peoples Gas states that the law applicable to this circumstance is clear. Management acts prudently when it makes decisions exercising a:

> standard of care which a reasonable person would be expected to exercise under the circumstances encountered by utility management at the time decisions had to be made. In determining whether or not a judgment was prudently made, only those facts available at the time the judgment was exercised can be considered. Hindsight review is impermissible. Imprudence cannot be sustained by substituting one's judgment for that of another. The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being 'imprudent'.

Illinois Commerce Comm'n v. Commonwealth Edison Co., ICC Docket No. 84-0395 (Order Oct. 7, 1987) at 17, 1987 Ill. PUC Lexis 68 at *34. There is no doubt or difference of opinion about this standard. *See, e.g., Illinois Power Co. v. Illinois Commerce Comm'n*, 339 Ill. App. 3d 425, 790 N.E.2d 377 (5th Dist. 2003). This same standard is quoted by Staff witness Mr. Seagle in his testimony. Staff Ex. 6.0 at 5.

Peoples Gas states during 2012, after the direct filing in this proceeding, Peoples Gas determined that certain unforeseen items would affect the capital spend for 2012, including (1) rock was encountered at depths that interfered with the placement of pipe and valve clusters, coupled with the City's atypical requirement for deep shoring for certain excavations; (2) AMRP unexpectedly incurred additional costs complying with new City of Chicago Department of Transportation ("CDOT") Regulations and Peoples Gas' cross bore program; and (3) the depths, sizes, and configurations of other exiting utilities were often not as indicated on as-built documents. NS-PGL Ex. 21.0 at 2-6. Peoples Gas states that not knowing this condition at the time of design or bidding, extra work was required of AMRP contractors as well as Peoples Gas engineering, and often required plan changes and re-permitting and Chicago Office of Underground Construction ("OUC") approval. *Id.* Peoples Gas states that no party contested that all of these circumstances were unforeseen and to assert otherwise would be impermissible hindsight review. NS-PGL Init. Br. at 32; NS-PGL Rep. Br. at 38. Peoples Gas states it took action to curtail costs to limit the increase in the 2012 budget to $20 million (resulting in a total 2012 budget of $220 million), which included suspending work on several projects, work on lower priority projects, and overtime costs

on non-critical AMRP work. NS-PGL Ex. 21.0 at 2-6. Taking no action in light of these unforeseen circumstances would have been imprudent. NS-PGL Init. Br. at 33.

Despite these unforeseen obstacles, Peoples Gas states that it still installed 132 miles of new main, retired 118 miles of old main, restored 141.6 miles, installed 13,289 new service pipes, installed 28,168 new meter regulator sets, and installed 3.5 miles of new high pressure steel interstation main. NS-PGL Ex. 49.0 Corr. at 7-8. Staff agreed these facilities already are or will be used and useful in serving customers. Tr. at 622-627; Tr. at 340-345. In addition, Staff agreed that the 2012 AMRP costs included in rate base (unadjusted by his proposal) is reflective of the work performed. Staff also acknowledged that Peoples Gas revised the 2012 AMRP budget to $220 million in supplemental direct testimony and then actually achieved that target. Tr. at 620. Thus, Peoples Gas concludes that not contesting that the revised 2012 AMRP work was prudent, reasonable in amount, and used and useful in providing customer service, Staff's adjustment to rate base for 2012 AMRP project costs is punitive. NS-PGL Init. Br. at 33.

Peoples Gas also states that it has demonstrated that it has appropriately developed a schedule for AMRP for the short term as well as the long term. Peoples Gas developed a detailed AMRP Construction Strategy and a 20-year deployment plan based on 5-year rolling periods. NS-PGL Ex. 49.0 Corr. at 14-15. Based on the zonal approach, Peoples Gas' service territory is delineated into three shops with a breakdown of AMRP projects per shop. *Id.* at 14-15, 22-25. Projects are then scheduled based on known drivers such as system needs, public improvement opportunities, community events, and street resurfacing projects. *Id.* Peoples Gas then sets project milestones upon which it works closely with winning contractors to establish a detailed block by block schedule. *Id*. Thus, Peoples Gas states that Staff's claims that construction work is left to the discretion of the contractors is incorrect. In fact, Peoples Gas has final approval over the contractor schedules to ensure they remain in line with the established milestones. *Id*. Given variables such as coordination with the City's public improvement and resurfacing projects and community events, it is impractical and impossible for Peoples Gas to create a detailed 20-year schedule for every street in its service territory. NS.PGL Rep. Br. at 36. Peoples Gas explained that it intentionally set more aggressive installation goals in the first two years of construction in order to gain the necessary momentum that is critical to success. NS-PGL Ex. 49.0 Corr. at 9-10.

Further, contrary to Staff's claims, Peoples Gas does have a process in place to track the progress of AMRP and that there is oversight of its contractors. NS-PGL Ex. 49.0 Corr. at 22-25. Under Peoples Gas plan, each contractor submits weekly updates to the PMO progressing all the activities on their portion of the detailed schedule. *Id*. In turn, the PMO then does a schedule analysis on each contractor to see if the milestone dates will be impacted. *Id.* Peoples Gas' 2011-2012 AMRP Construction Strategy White Paper and its Five Year Construction Plan White Paper identify the plan of work to be accomplished in future years. *Id*. at 14-15, 22-23. Each year that construction work is bid and awarded will follow the very detailed planning process explained by Utilities witness Mr. Hayes. *Id* at 22-25. Peoples Gas demonstrated that it has

appropriately developed a schedule for AMRP deployment for the short term as well as the long term. Furthermore, Peoples Gas appropriately tracks contractor work. Id at 22-25.

Moreover, Peoples Gas has demonstrated its ability to schedule work by actual experience as well. In 2012, Peoples Gas actually installed 132 miles of new main (170 miles forecasted), actually retired 118 miles of main (110 miles forecasted), restored 141.6 miles, installed 13,289 new service pipe, 28,168 meter regulator sets, and 3.5 miles of high pressure main. NS-PGL Ex. 49.0 Corr. at 7-8. Except for new mains installed, all of these totals exceed 2011 construction totals, the first year of construction. NS-PGL Init. Br. at 33-34. Peoples Gas states that it is clear that it is ramping up AMRP as the Commission acknowledged in the 2009 Rate Case. *Id*. Additionally, Peoples Gas has demonstrated that it can appropriately forecast costs. NS-PGL Ex. 34.0 at 9-11; NS-PGL Ex. 49.0 Corr., 25-29.

Finally, Peoples Gas states that Staff's calculation of its adjustments to rate base for 2012 and 2013 AMRP costs is seriously flawed. Particularly, Staff's analysis is based on outdated information as he does not use the revised 2012 work plan, he fails to account for a large volume of work completed, and he fails to account for the fact that costs of removal are not included in rate base. NS-PGL Ex. 34.0 at 4-5; NS-PGL Ex. 49.0 Corr. at 30; Tr. at 617-618. Staff also does not consider costs associated with design, engineering, project management, construction management, construction inspection, materials, *etc*. NS-PGL Ex. 34.0 at 5. Further, the various categories of work that Staff excludes from its analysis is work he agrees should be done and yet he did not correct his calculation. *Id*. at 5-6; NS-PGL Cross Exs. 11 and 12. Finally, and most importantly, Staff's analysis is incorrect as the evidence demonstrates that the 2012 costs included in rate base are reflective of the work actually completed in 2012. NS-PGL Ex. 49.0 Corr. at 7-8, 30. In fact, Staff agrees that the 2012 AMRP amounts reflected in rate base represent work actually performed. Tr. at 627. Furthermore, there is no evidence that Peoples Gas will not effectively and efficiently manage AMRP in 2013.

Therefore, Peoples Gas concludes that Staff's adjustments for 2012 and 2013 AMRP costs are without merit as they disallow costs that were or will be prudently incurred, reasonable in amount and used and useful in providing customer service. Peoples Gas avers that adopting these improper adjustments would cause Peoples Gas not to sustain its investments in AMRP resulting in a major loss for customers and in a loss of a significant number of good-paying construction jobs that have already been created. NS-PGL Ex. 22.0 2nd Rev. at 2. This conclusion is supported by Local Union No. 18007, Utility Workers Union of America, AFL-CIO ("UWUA"). See UWUA Local 18007 Ex. 1.0 at 4-5, 6-7.

<u>Section 8-102 Investigation</u>

Staff has argued that the Commission should initiate a proceeding under Section 8-102 of the Act because AMRP has accomplished little and has been mismanaged. Further, for the first time in its Initial Brief, the AG supports Staff's recommendation.

CUB-City recommend that the Commission consider Staff's recommendation. Peoples Gas argues that the recommendation should be rejected. Peoples Gas argues that the underlying premise to Staff's proposed Section 8-102 investigation, namely that AMRP has accomplished little and has been mismanaged is false. The evidence demonstrates that significant work has been completed since construction began in the spring of 2011. Furthermore, the record demonstrates that Staff is not aware of the specifics of the AMRP plan, the goals of AMRP, or the actual work that has been completed. Therefore, Peoples Gas concludes that Staff's recommendation should be denied.

Peoples Gas explained that when the Commission approved Rider ICR, the AMRP plan was not submitted until August 2009, with surrebuttal testimony in that case. In fact, the Commission noted that only some of the activities had begun for the 20-year program, which should be completed by 2030. At December 31, 2009, 20 full calendar years remained until 2030, so contrary to Staff's assertion, AMRP began in 2010. Further, in approving Rider ICR, the Commission understood that implementation of AMRP would begin in 2011 and there would be a five-year ramp up period, a period which ends in 2015. In 2010 and the beginning months of 2011, Peoples Gas engaged in planning that included (1) system studies assessing the areas of the gas distribution system to be targeted for replacement, partnering with Jacobs Consultancy as the Project Management Office consultant; (2) identification of resource needs; (3) development of staffing plans; and (4) engineering planning. NS-PGL Ex. 49.0 Corr. at 5. In fact, in early fall 2010, detailed engineering plans were being submitted to the City's OUC. *Id.* Implementation of AMRP began Spring 2011 and Staff noted, Peoples Gas encountered certain permitting, coordination, and material delivery issues. However, this is not new information as it is part of the record in the Utilities' 2011 rate cases. In the first full year of construction, 2012, these issues have not reoccurred. NS-PGL Ex. 49.0 Corr. at 10-11.

Based on its detailed planning and expert management of AMRP, Peoples Gas states much has been accomplished in less than two years as depicted by the chart above. NS-PGL Init. Br. at 35-36. As demonstrated by the evidence, as AMRP is ramping up, significant work is being accomplished. *Id*. at 37. In 2012, more main was retired than in the last three calendar years. NS-PGL Ex. 49.0 Corr. at 7-8. In fact, in each category of work except for new main installed, Peoples Gas states that it has surpassed the work completed in 2011 and in one instance doubled the work. NS-PGL Init. Br. at 37. Further, at December 31, 2010, averaging the work to be completed over the 20-year period, Peoples Gas meets or exceeds the average in many key categories. Tr. at 340-345. Significant work has been accomplished even in 2012 when Peoples Gas had to react to rising costs due to unforeseen circumstances. Peoples Gas argues that Staff appears unaware of key parts of the AMRP plan, the main goals of the plan, and the actual work that was completed. Tr. at 327 – 351. Peoples Gas states that it is unclear on what Staff bases its assertions that "little has been accomplished" or that AMRP has been "poorly managed." NS-PGL Init. Br. at 37-38. Also, the scope of the recommended investigation further demonstrates Staff's unfamiliarity with AMRP. NS-PGL Ex. 49.0 Corr. at 17-20. Finally, Peoples Gas demonstrated that it can manage costs when faced with unforeseen events as in 2012. NS-PGL Rep. Br. at 36.

Finally, Peoples Gas argues that the AB and CUB-City arguments regarding its commitment to AMRP are without merit. Peoples Gas states that these arguments are dispelled based on the level of investment Peoples Gas has made in 2012 and plans to make in 2013. Peoples Gas states that it cannot afford to maintain such large investments if its rate base is reduced based on unsupported adjustments as proposed by Mr. Seagle and Staff as well as intervenors positions regarding year-end rate base. Peoples Gas cannot keep to its planned levels of investing in its system without a cost recovery that, over time, meets the costs of those investments. This cannot occur if costs that are prudently incurred, reasonable in cost, and used and useful in providing utility service are excluded from rate base as Staff proposes. Significant under-recoveries also can erode the ability of a utility to raise capital at a reasonable cost.

Peoples Gas also states that the CUB-City argument that the Utilities cannot assure the safety of the system is a red herring and disingenuous since CUB-City also apparently are adopting Staff's adjustments to AMRP. AMRP is a program that enhances safety and reliability to its customers. It identifies and replaces those segments of main that may have the highest risk. CUB-City appears to be seeking a 100% guarantee in the safety of Peoples Gas system. However, there can be no absolute guarantee as there are inherent risks in any system. Tr. at 197. Finally, Peoples Gas states that without the ability to recover its AMRP investments, at risk are (1) 500 recently created highly skilled jobs; (2) the employment of 120 Gas Workers Union Local 18007 field personnel to offset the added AMRP manpower support; and (3) the new apprenticeship program. NS-PGL Ex. 22.0 2nd Rev. at 7. Failure to allow Peoples Gas to adequately recover these costs, as it is allowed to do for all plant investment, would jeopardize such an important program.

Staff

<u>Section 8-102 Investigation of AMRP</u>

Given the uncertainty surrounding Peoples' Accelerated Main Replacement Program ("AMRP") and the Company's ability to complete the AMRP successfully, the Commission should conduct an investigation of the AMRP under Section 8-102 of the Act (220 ILCS 5/8-102), regardless of whether it accepts Staff witness Seagle's AMRP adjustment, which it should. Staff Ex. 20.0 at 23. Such an investigation will ensure that Peoples will complete its AMRP on a going forward basis at a reasonable cost and within a reasonable time. *Id. at* 25. In his testimony, Staff witness Roy Buxton described the scope and nature of an appropriate investigation, including a verification phase and future rate case testimony. *Id.* at 3-9. The investigation will cost an estimated $2.5 million; however, given the significant cost of the AMRP to date, the cost of the investigation is justified. *Id.* at .27-28. While Peoples will initially bear the cost of the investigation, the utility can eventually recover the cost from ratepayers through the normal ratemaking process. *Id.* at 28-29.

Peoples Gas proposed its AMRP four years ago in its February 25, 2009 filing in Docket No. 09-0167; however, since then, the AMRP has fallen behind schedule, while consuming its budget on what little work it has completed. *Id*. at 8-9. The AMRP

encountered problems with scheduling, materials delivery, government permits, and underground utility locating. *See* Staff Ex. 20.0, Attach 20.01. Peoples Gas has given the Commission no reason to believe that it can complete the AMRP in 20 years, and no evidence for the total cost of the eventually completed AMRP. Further, and more troubling, there is no evidence that Peoples Gas can solve its AMRP problems. *Id.* at 8-9. Staff witness Brett Seagle's recommended adjustments to the capital cost of the AMRP discussed below provide further support for Staff's recommendation that the Commission examine the program as outlined in Mr. Buxton's testimony.

It is clear that AMRP is a matter of significant public interest for both Peoples Gas and its ratepayers. In Docket No. 09-0167, Staff witness Harry Stoller explained his understanding of the condition of Peoples Gas' mains and the need for a gas main replacement program.

> While others might disagree with my characterization of Peoples Gas' distribution system, the Marano testimony leads me to conclude that it is old, it is antiquated, and it is approaching the point that further aging and deterioration will eventually cause replacement to maintain public safety to become an emergency matter rather than one which can be reasonably planned and executed. Whether or not the twenty-year replacement program Mr. Marano has advocated will get the job done soon enough is probably anybody's guess. What I am convinced of is that Peoples Gas should begin the replacement program very soon to avoid the possibility of a later emergency situation. ICC Staff Ex. 14.0 at 6.
>
> *Id*. at 12.

Staff witness Buxton continues to agree with that assessment.

The Commission declared its support for the AMRP in its Order in that same docket, where the Commission made the following statements among others:

> In other words, while the Commission would surely initiate a Section 8-503 proceeding on the basis of Staff's account if it were faced with Company obstinacy or disregard . . .
>
> With Staff's testimony, <u>accelerated system improvement has become for the Commission a matter of the public interest more so than just a Company proposa</u>l. Final Order, Docket No. 09-0167, January 21, 2010, at 194.
>
> *Id.* at 13. (emphasis added)

Four years after Peoples proposed the AMRP, Peoples Gas should have the AMRP well underway. Four years is 20 percent of a 20-year AMRP schedule. *Id.* However, Peoples is still experiencing considerable problems. It has completed only 95 percent

of the AMRP work it planned for 2011, less than 50 percent of the work it planned for 2012, and it has reduced the amount of work it plans to complete in 2013. NS-PGL Ex. 21.1 at 1. While Peoples Gas points to the amount of main replacement that occurred during 2011, 2012 and 2013, (NS-PGL Ex. 49.0 at 6-8, Tr. at 339-345), Staff notes that the total amount is irrelevant if the amount projected and budgeted for is not accomplished, as this is the amount Peoples Gas seeks to recover from ratepayers. Ratepayers should not bear the burden of Peoples Gas' delays in the AMRP and should only be required to pay for what Peoples Gas has accomplished. The Company was not ready to begin the AMRP when it made its filing in Docket No. 09-0167, and it is Staff's opinion that Peoples Gas is not ready now. Staff Ex. 20.0 at 17-18.

The Commission apparently assumed in its Final Order in Docket No. 09-0167 that Peoples Gas possessed a significant level of ability to perform gas main work in Chicago. Order, Docket No. 09-0167, January 21, 2010, at 195. However, an examination of information in the record in this proceeding tells a different story. The Company did not expect and took no advanced actions to prevent its greatly increased construction pace to overwhelm the City of Chicago's Office of Underground Coordination. *See* Staff Ex. 20.0 at 15 and Attach 20.01. Peoples Gas failed to expect and plan for the Chicago Department of Transportation having difficulty keeping up with Peoples' accelerated pace asking for construction permits. Peoples Gas failed to anticipate and plan for Digger (the underground locating service for the City of Chicago) not being able to keep pace with Peoples Gas' much higher volume of requests to mark utility locations in the field. Additionally, Peoples Gas allowed too little lead time for delivery of construction materials. Staff Ex. 20.0 at 14-16. According to the Company's own witness, Peoples Gas is in a position where it will spend additional dollars at the same time it will accomplish less volume of work. NS-PGL Ex. 21.0 at 1.

Peoples Gas claims to have a 20-year plan for the AMRP, but the plan is not sufficiently detailed. There is no budget in the plan. The plan does not even mention costs. *Id.* at 19. According to Peoples Gas witness Mr. Phillip M. Hayes, Peoples Gas' senior management tells its staff how much money it can spend each year on the AMRP, then the staff determines which gas mains it should replace first and how many mains it can replace with the funds that senior management has made available. *Id.* at 18. That is not long-term planning. Under these conditions, without a plan, Peoples Gas will be unable to perform the AMRP with any efficiency or effectiveness. Neither the Commission nor any other interested party will have any measure of the Company's adherence to a schedule because there is no schedule. Likewise, the Commission cannot know whether Peoples Gas is experiencing cost overruns because there are no cost estimates. *Id.* at 19-20.

The cost of Staff's recommended investigation of AMRP is difficult to predict, but an estimate of the cost of the investigation less the cost of providing the investigation results in future rate cases is approximately $2.5 million dollars. *Id.* at 27. This estimate includes the cost of a one-year investigation phase resulting in recommendations and a two-year verification phase where the consultant checks

Peoples Gas' work for implementing the recommendations from the investigation phase. *Id.* at 27-28.

While one of the goals of regulation is for utilities to provide safe and reliable service (220 ILCS 5/1-102), there is also the goal, among others, that utilities are to provide least cost public utility service. *Id*. Accordingly, with respect to the goal of least cost service, only the cost of prudent and used and useful AMRP construction can be included in rate base and recovered from ratepayers. 220 ILCS 5/9-211. Consistent with the first goal of safe and reliable service, the Commission has already acknowledged the importance of the AMRP for safe gas service and the urgency to complete the project in 20 years. No party should dispute that the AMRP should move forward as quickly and efficiently as possible. This is not possible given Peoples Gas' failure to provide evidence of real AMRP plans or budgets and given that the utility has proven that it cannot meet its intended construction goals in 2011, 2012, or 2013. Staff's recommendation to reduce Peoples Gas' AMRP related gas rate base by almost $219 million[2] discussed below, which is consistent with the second goal of least cost service, demonstrates that careful attention must be paid to Peoples Gas' AMRP on a going forward basis through an investigation as recommended by Staff witness Buxton. This Section 8-102 investigation is essential to assuring that this massive project of significant public interest continues forward in a manner that does not waste large amounts of ratepayer money simply due to mismanagement. Therefore, to assure that the AMRP moves forward in the most expedient, cost-effective manner, the Commission should adopt Staff's recommended investigation of Peoples Gas' AMRP.

AMRP Adjustment

Staff witness Seagle recommended that the Commission exclude certain costs associated with Peoples Gas' AMRP from its base rates. Specifically, Mr. Seagle recommended that the Commission remove $95,794,000 in 2012 and $122,804,000 in 2013 from Peoples Gas' requested ARMP costs. Staff Ex. 16.0 at 22.

Mr. Seagle testified about two concerns regarding the manner that Peoples Gas pursued this project. First, Peoples Gas lacks appropriate methodology to plan and track the project. Second, Peoples Gas' projection of work completed for 2012 and 2013 missed its estimate by a factor of almost two. Staff Ex. 6.0 at 39. Based on these concerns, Mr. Seagle proposes disallowing a portion of the costs that Peoples Gas claimed it would incur. Mr. Seagle based his calculation on a comparison of the amount of actual work completed versus the amount of work Peoples Gas projected it would complete in 2012 and 2013.

Construction Methodology

Mr. Seagle testified that Peoples Gas' methodology for how it developed its AMRP schedule lacks any reasonable policies and/or procedures to provide guidance

[2] $95,794,000 disallowance for 2012 AMRP construction plus $ 122,804,000 disallowance for 2013 AMRP construction equals a total disallowance of $218,598,000. ICC Staff Ex. 16.0, p. 26.

for its Engineering and Operations personnel to develop a workable schedule. Staff Ex. 16.0 at 23. Staff noted that this type of information is necessary for the Company to establish the project milestones that it uses in the bidding process. *Id.* Of particular concern is that Peoples Gas appears to leave the actual planning of construction work to the discretion of the contractor performing the work at street level. Mr. Seagle stated that this type of planning is inadequate because no policies or procedures were in place before the meetings were held between engineering personnel, operations personnel, construction managers, and contractors. *Id*. Further, Mr. Seagle found that the lack of adequate planning by Peoples Gas' management is likely a factor causing Peoples Gas to not complete its planned or forecasted AMRP construction and restoration work within the time allotted.

Peoples Gas disputes Mr. Seagle's recommendation. In particular, Peoples Gas attempts to demonstrate that the development of the AMRP schedule is "best practice." (NS-PGL Ex. 49.0 at 24) Peoples Gas states that the construction installation schedule is left to the contractors' discretion. *Id*. In fact, Company witness Mr. Philip Hayes states: "To get a more detailed schedule developed, best practice has the installation contractor in turn develop a block by block approach as to when the work is planned as they are the ones supplying and directly overseeing the contractors labor and equipment resources." *Id.* Staff disagrees with Mr. Hayes contention.

Staff's review reveals that Peoples Gas' "best practices" are inadequate given the poor progress that Peoples Gas has made on this project compared with its projections. Staff Ex. 6.0 at 39. Indeed, Peoples Gas witness Hayes explains that Peoples Gas has not yet completed all of the <u>2011</u> AMRP distribution projects. Mr. Hayes states that approximately 95% of the 2011 AMRP distribution projects are completed, leaving approximately 5% of the 2011 AMRP distribution projects unfinished. NS-PGL Ex. 34.0 at 10. Further, Peoples Gas provided no documentation demonstrating it used sound procedures or policies in association with its ARMP project. Instead, Peoples Gas provided vague generalizations of how it intends to provide guidance to contractors, so that the contractors can develop an actual plan directly before the contractor begins construction at that particular street or block. Staff Ex. 16.0 at 24-25.

Aside from the inadequate "oversight" of its contractors, Peoples Gas also lacks a means to track the project sufficiently. Peoples Gas provided an AMRP Weekly Report, Summary Status (NS-PGL Ex. 34.3) that shows the percentage of completion of the 2011 and 2012 AMRP distribution projects, as well as the Accelerated Six Distribution Projects and the High Pressure Main Installation Project. Peoples Gas claims these documents demonstrate that it is making better progress towards AMRP construction and restoration goals compared to the current rate of completion of AMRP construction goals. However, this document does not provide any detail regarding plans, discussions, or meetings held to address issues with regard to meeting AMRP construction and restoration goals. Without this detail, the Commission and Staff are unable to determine if Peoples Gas is making better progress towards AMRP

construction and restoration goals compared to the current rate of completion of AMRP construction and restoration goals. Staff Ex. 16.0 at 25.

Based on the information detailed above, Mr. Seagle determined that the methodology applied to develop Peoples Gas' AMRP schedule lacks any reasonable policies and/or procedures to provide guidance for its Engineering and Operations personnel in developing a workable schedule. Therefore, Staff recommends that the Commission accept Mr. Seagle's position that Peoples Gas' actions were imprudent, and exclude the portion of Peoples Gas' costs associated with the AMRP from its rate base.

Work Completed

Mr. Seagle testified that Peoples Gas failed to complete the level of planned AMRP construction and restoration work that Peoples Gas claimed it would conduct in 2012 and 2013. Staff Ex. 6.0 at 39. Mr. Seagle's comparison of planned AMRP work to actual AMRP work completed showed that Peoples Gas' contractors were well behind the planned or forecasted schedule, which Peoples Gas utilized in its cost projections for the project. *Id*. Mr. Seagle found that Peoples Gas only finished about *half* of the AMRP work it planned to complete, but incurred approximately the same capital costs. In other words, the project costs per mile were almost *double* Peoples Gas' projections. *Id*. at 39-40. Peoples Gas projected it would install 165 miles of gas main in both 2012 and 2013, but Peoples only met 53% of its goal in 2012 and has now revised its forecasted miles in 2013 to approximately 50% of its original projections. Staff Ex. 6.1, Sched. 6.1 P. Further, as noted earlier, Peoples Gas still has 5% of its 2011 work yet to complete. NS-PGL Ex. 34.0 at 10.

Peoples Gas' lack of progress on this project is a result of its reliance on inaccurate assumptions. Staff Ex. 6.0 at 41. Peoples Gas noted stated that it had yet to complete a full year of the program where the Company could collect the full cost and resource data, and then be able to accurately forecast for future years. *Id*. Staff does not dispute that Peoples lacked a full year of activity; however, Peoples Gas should have unequaled expertise in every aspect of planning, designing, constructing, maintaining, and replacing underground gas mains in Chicago. With 150 years experience digging up Chicago streets, the Company should have a solid understanding of just how much funding it will expend on each type of construction project and should have taken preemptive action to mitigate budget and scheduling complications. Staff's review of the record indicates that no mitigation took place. Staff Ex. 20.0 at 4-6.

Peoples Gas' use of inaccurate assumptions coupled with its inability to achieve any reasonable percentage levels of project completion, led Mr. Seagle to determine that Peoples Gas' failure was the result of its own lack of prudence in conducting the AMRP project.

Calculation of Adjustment

Mr. Seagle formed the basis for his adjustment by comparing the percentage completion rate for a number of categories that Peoples Gas tracked within its project. Staff Ex. 6.0 at 37-38. In particular, Mr. Seagle's calculation relied on the number of miles of main installed, miles of main gassed, gas services installed, meters installed, and the miles of old main removed from service. *Id*.

Peoples Gas disputes the need for an adjustment, and articulated two criticisms of Mr. Seagle's calculation. First, Peoples Gas contends that Mr. Seagle did not include in the calculation of his adjustment the costs associated with the carry over work not completed in 2011. NS-PGL Ex. 34.0 at 4-5. Mr. Seagle acknowledged this oversight and corrected his calculation to account for the carryover work. Staff Ex. 16.0 at 21.

Second, Peoples Gas stated that Mr. Seagle did not include all of the categories that it tracks in his calculation. NS-PGL Ex. 34.0 at 4-6. Mr. Seagle explained that his calculation did not include the category labeled "Main – As Built "in the calculation because it was not clear what the category "Main – As Built" represents. Staff Ex. 6.0 at 38. Mr. Seagle also excluded two other categories from his calculation due the nature of those categories, "Contractor Interim Restoration" and "Contractor Final Restoration." *Id*. Mr. Seagle did not use these categories because having interim or final restoration in place would not affect whether or not Peoples Gas could activate or use the gas piping system, plus Peoples itself admitted that some of these topics are not representative of the level of work completed. *Id.*; NS-PGL Ex. 34.0 at 6.

For the reasons stated, Mr. Seagle continues to recommend that the Commission exclude from base rates the portion of costs associated with Peoples Gas' Accelerated Main Replacement Program. Specifically, Mr. Seagle recommends that the Commission remove $95,794,000 in 2012 and $122,804,000 in the 2013 of People Gas' requested rate base addition associated with the AMRP. Staff Ex. 16.0 at 22.

AG

The AG argues that Peoples Gas is asking ratepayers to cover in rates AMRP investments that include a projected test year level of $220 million. These AMRP investment amounts promise to remain high for years to come as the Company seeks to replace approximately three thousand miles of cast iron main and associated infrastructure over the next few decades. From the outset, it should be noted that the People do not debate whether outdated, brittle, or otherwise dangerous gas mains or segments should be replaced. If the mains in question are threatening public safety or interfering with the delivery of reliable service, then the mains must be replaced. However, given the significant dollar amounts associated with the AMRP cost recovery from ratepayers, compounded with the critical safety claims made by the Company related to this project, the People have serious concerns about the spiraling costs and PGL's lack of clear work plans. The People support Staff witness Buxton's proposal to engage an independent audit of the Company's expenses, methodology, and work plans. The Commission has clear authority under Section 8-102 and general authority under Section 8-505 of the Act to ensure "to require every public utility to maintain and

operate its plant, equipment or other property in such manner as to promote and safeguard the health and safety of its employees, customers and the public… ." 220 ILCS 5/8-505. Included within this investigation should be a re-examination of the viability and reasonableness of the 2030 estimated completion date from safety, reliability and economic perspectives.

The Act requires the Commission to establish just and reasonable rates. 220 ILCS 5/9-101. In order to include an investment in rate base, that investment must be both prudently incurred and used and useful. 220 ILCS 5/9-211. It is the Commission's duty to determine whether capital improvements or additions to plant are reasonable. *Business and Professional People v. Ill. Commerce Comm. ("BPI II"),* 146 Ill. 2d 175, 196 (1991). Based on the record evidence in this docket, the Commission should have concerns that the project is being reasonably and efficiently managed. The record evidence supports closer Commission scrutiny.

The Company repeatedly hinges its commitment to timely completion of this project "if appropriate and timely recovery is provided." See, *e.g.*, NS-PGL Ex. 34.0 at 11. Mr. Hayes spent approximately four pages of his six page supplemental direct testimony discussing unforeseen costs and various costs that are outside the Company's control. *See, generally*, NS-PGL Ex. 21.0 at 2-5. However, he dedicates no more than *two lines* of his testimony discussing the prudence of spending on this project. In fact, he merely presents the conclusory and dismissive explanation that: "The capital expenditures incurred as a result of the project are or will be prudently incurred, reasonable in cost, and used and useful in providing utility service." NS-PGL Ex. 21.0 at 6. Despite the dramatic increases in costs year over year, the Company simply admits that it "cannot control the unexpected." NS-PGL Ex. 34.0 at 10.

The Company's attempts to outline cost saving mechanisms that it has in place backfire and instead demonstrate the fact that ratepayers are getting less plant investment for more money. Mr. Hayes, when discussing the reasonableness of spending hundreds of millions of dollars every year, testifies as to "rigorous cost reducing measures." NS-PGL Ex. 34.0 at 10-11. However, closer analysis reveals that these "rigorous cost reducing measures" primarily include "suspending a portion of the 2012 planned construction work, completing active projects to a safe condition if we could not complete them in total, suspending all overtime, re-prioritizing the work being performed by Peoples Gas crews, suspending consulting engineers work, and reducing contracted staff." NS-PGL Ex. 34.0 at 10. Essentially, in order to save money and cut costs, the Company is stopping the very work that they claim is critical to safety and reliable delivery of utility service. Despite the Company's "rigorous cost reducing measures," Mr. Hayes admitted that the Company still spent $12 million more than it had originally budgeted. NS-PGL Ex. 34.0 at 11. Indicative of this overspending is that, apparently, one of the ways in which PGL seeks to save money and control costs is to start new pilot programs and spend more money. PGL lists as one of the efforts to control costs the development of a pilot for the cross-bore program. NS-PGL Ex. 34.0 at 11-12. As noted in the Cross Bores Section of this brief, this is a program that, itself, is adding almost $6 million in unjustified expenses and is rife with problems.

Regardless, the cross-bore program was being investigated as early as the 1990s, (Tr. at 373), so the People are uncertain how this additional program is only now being launched as a pilot. It is equally unclear as to how it will save costs on AMRP.

PGL needs to demonstrate that it can appropriately manage its costs, something Staff's engineering witnesses believe it has not shown. See ICC Staff Ex. 16.0 at 22; ICC Staff Ex. 20.0 at 17. Since this docket began, the projection for AMRP expenses has been a moving target, to say the least. By the time rebuttal testimony was filed, the 2012 budget had increased by 10% to $220 million. NS-PGL Ex. 21.0 at 1. Further troubling is that throughout this docket, PGL's cost estimates have varied wildly between testimony filing dates, and the Company appears to shift much of the blame for this on "unforeseen conditions." NS-PGL Ex. 21.0 at 1. The People acknowledge that the reality of running a project of this size is that costs will vary and unforeseen events will arise that cause increases in spending. PGL's cost overruns, however, should be a red flag to the Commission and proof that the project requires additional scrutiny.

In fact, as AG witness Mr. Effron noted, by PGL's own estimates, the non-budgeted and unforeseen conditions would have increased the total cost of AMRP additions in 2012 by $62 million based on the scope of work originally budgeted for 2012. AG Ex. 2.0 at 9. However, the magnitude of the cost increases was reduced by $42 million by decreasing the scope of the work, including the suspension of work on low priority projects and the suspension of non-critical overtime hours being charged to AMRP by PGL'S work crews. NS-PGL Ex. 21.0 at 5-6. Through the end of September, the actual spending on cast and ductile iron main replacement in 2012 was approximately $21.6 million above the budgeted level of such spending. AG Cross Ex. 9.

PGL installed 154.5 miles of mains in 2011[3] and 92.1 miles of mains in 2012.[4] PGL Ex. 34.3. In his rebuttal testimony in this case filed in December of 2012, Mr. Hayes stated that "Peoples has still completed only 95 percent of work intended for 2011 and less than 50 percent of work intended for 2012. NS-PGL Ex. 34.0 at 10. Further, Mr. Hayes says that "Peoples will reduce the amount of work it will complete in 2013. *Id.* at 11. Finally, Mr. Hayes summarized the crux of the problem with the Company's AMRP when he testified that the Company "is in a position where additional dollars will be spent while at the same time less volume of work will be accomplished." NS-PGL Ex. 21.0 at 1. By their own admission, the Company seems to be asking ratepayers to pay more and receive less.

Related to the Company's demands for recovery is the question of timing. The Commission explicitly noted the importance of timely completion of AMRP in 09-0166/09-0167:

[3] It is unclear, however, whether the 2011 total reflects mains that were scheduled to be replaced in 2009 or 2010.
[4] This total does not include replacements of mains in 2012 that were scheduled to be replaced in 2011.

> Due to the many benefits that the accelerated plan provides to ratepayers, the Commission is of the opinion that time is of the essence and hereby requires completion of the acceleration plan project by 2030.

ICC Docket 09-0166/09-0167 Final Order (January 21, 2012) at 196.[5] In that case, the People questioned the validity of the 2030 date because it was rooted in a very high-level, economic analysis for the purpose of gaining approval of Rider ICR – not on any kind of safety and reliability analysis.[6]

Regardless of the 2030 date's validity, the Company has made it clear that it no longer considered itself *required* to achieve that completion date since the reversal of the Commission's decision in Docket No. 09-0166/0167 approving Rider IC R. AG Cross Ex. 9. Staff witness Buxton testified, "the Commission still needs assurance that Peoples has a plan to complete its AMRP in 20 years as both Peoples and the Commission seemed to intend in the January 21, 2010 Order in Docket No. 09-0167." ICC Staff Ex. 20.0 at 23. This assurance is lacking in the instant docket. The only difference following the "acceleration" of the program is that the Company, as noted above, rests timely completion on being provided "appropriate and timely recovery." NS-PGL Ex. 34.0 at 11. The Company wavers even further in its response to AG Data Request 22.01, when the Company explained that "if, over time, Peoples Gas does not recover the costs of the AMRP projects, then at some point funding the AMRP projects will become infeasible as a matter of practical business reality." AG Cross Ex. 15. Therefore, it is unclear what financial conditions meet the Company's test of adequate cost recovery for purposes of continuing the program. As part of any audit, the Commission should revisit the validity of the 2030 completion date to ensure that it comports with standards of safety, reliability, and cost-efficiency.

Historically, too, PGL has failed to provide a solid work plan. As the People noted in its Initial Brief in ICC Docket 09-0166/09-0167:

> The fact that Peoples is unwilling to formally commit to a specific plan or schedule for Commission approval takes on new meaning when considered with a Rider ICR proposal that permits surcharges to be assessed on the first dollar of investment in the applicable six plant accounts.
>
> The Company's request to approve a cost recovery mechanism before the Commission has even evaluated a specific implementation plan

[5] The People acknowledge that the portion of the Final Order in this docket was overturned by the Appellate Court in *People ex. rel Madigan v. Illinois Commerce Comm'n*, 2011 IL App (1st) 100654. However, the language of the Order in 09-0166/09-0167 is still representative of the Commission's original intent related to AMRP.

[6] PGL examined three different timing scenarios for acceleration: 2025, 2030 and 2035. Tr. 809; PGL Ex. SDM-1.0 at 50, 51. The Companies' witness at the time, Mr. Marano, concluded that a 2030 completion date would be the "most practical and economical" of the three choices. ICC Docket No. 09-0166/0167, Tr. at 810.

> for any acceleration proposal is a classic case of putting the cart before the horse that should be rejected out of hand by the Commission.

ICC Docket Nos. 09-0166/09-0167 AG Corrected Initial Brief at 27-28, filed on e-docket on September 30, 2009.[7] That same problem seems to be present in this docket. and the Company asks the Commission and ratepayers, to trust them and not sweat the details of a project that spans decades and will costs hundreds and hundreds of millions of dollars. The primary plan presented by PGL in support of AMRP is its Five-Year Construction Plan. *See* ICC Staff Ex. 20.0 at Appendix 2. Mr. Buxton characterized this as "a discussion of how Peoples intended to create a plan" rather than a detailed outline of a plan to allocate resources and begin construction. ICC Staff Ex. 20.0 at 19.

In the opinion of Staff witness Roy Buxton, "a public utility that has been digging up Chicago streets for over 150 years should have known enough to take into consideration the resource limits of the City of Chicago's various construction-related departments and offices." ICC Staff Ex. 20.0 at 16. However, by the Company's own admission, it is not making coordination of efforts a priority. In response to AG Data Request 10.17, the Company acknowledged on October 26, 2012 that:

> To date there has been no correspondence between Peoples Gas and the City of Chicago's Department of Transportation or Office of Underground Coordination in regards to forecasted 2013 AMRP expenditures on needed number of pipe location digging requests, construction permit requests, or City marking of existing underground facilities requests.

AG Cross Ex. 8. Despite being deep into 2012 calendar year, PGL had not yet had any correspondence or coordination with the City. It is this very lack of action on the part of the Company that is alarming to the People and demands Commission oversight. Indeed, as Mr. Buxton notes, other utilities operating in the City of Chicago do not appear to have such issues with coordinating their activities. ICC Staff Ex. 20.0 at 16-17.

The current protocol for replacing mains is unclear at best. Generally speaking, gas main segments which score above a 6.0 on the Main Replacement Index (MRI) scale represent a threat to safety. AG Cross Ex. 9. However, six segments with MRI above 6.0 remained unrepaired in 2012 with an unclear date on which they will be replaced. AG Cross Ex. 9. The Company's cryptic response to City data request dated November 13, 2012, on this very issue simply noted that:

> Gas main segments currently on the list will be replaced in 2012 or 2013. Only one segment is listed as being replaced in 2013 as it is part of the "2013 construction work" which will be awarded to a construction contractor in 2013 while the other segments were previously awarded for replacement as part of the "2012 construction work."

[7] The People ask that the Commission take administrative notice of the existing record in the Company's previous dockets where the parties are largely the same and similar issues are being addressed.

AG Cross Ex. 9. Currently, main segments with a Main Ranking Index (MRI) above 3.0 (which are viewed as "possible replacement candidates") account for only 3.2% of all of the main segments to be replaced. AG Cross Ex. 9; PGL Response to AG Data Request 10.16. There are, therefore, an arguably small number of mains in seemingly dire need to be replaced. Yet, the record evidence suggests that the Company has not made the replacement of these mains a priority. AG Cross Ex. 9. Despite such a relatively small percentage of "possible replacement candidate" mains, it does not appear that PGL took into account these mains when crafting their "zonal" approach, described in its Brief. See NS-PGL IB at 35. These inconsistencies in prioritization are unexplained and further support the need for more Commission oversight of the AMRP project.

Of additional concern to the People is that excessive authority may rest with the "shop manager" in determining whether certain mains will be replaced. The Company stated, in response to City Data Request 2.05 that "The shop manager has the authority to have gas main segments replaced based on field conditions regardless of the MRI value. Each situation is evaluated on a case-by case basis." AG Cross Ex. 9. More detail is needed for the Commission's review on whether this line of authority is reasonable.

In summary, as Mr. Buxton testified, "There is no reliable evidence before the Commission to allow it to determine how long Peoples will take to complete its AMRP or what the completed AMRP will cost." ICC Staff Ex. 20.0 at 25. Given the strong concerns that Staff has for the implementation of the Company's AMRP and the concerns raised by the People in this brief, the People urge the Commission to conduct an investigation of PGL's AMRP to determine whether the project has been or will be prudently undertaken and whether it is reasonable in cost.

As noted earlier, Section 8-102 of the Act (220 ILCS 5/8-102) grants the authority to the Commission to conduct such an audit. In relevant part, that section reads that:

> The Commission is authorized to conduct or order a management audit or investigation of any public utility or part thereof. The audit or investigation may examine the reasonableness, prudence, or efficiency of any aspect of the utility's operations, costs, management, decisions or functions that may affect the adequacy, safety, efficiency or reliability of utility service or the reasonableness or prudence of the costs underlying rates or charges for utility service. The Commission may conduct or order a management audit or investigation only when it has reasonable grounds to believe that the audit or investigation is necessary to assure that the utility is providing adequate, efficient, reliable, safe, and least-cost service and charging only just and reasonable rates therefor, or that the audit or investigation is likely to be cost-beneficial in enhancing the quality of service or the reasonableness of rates therefor.

220 ILCS 5/8-102.

Therefore, in light of the evidence in the record supplied by the Company, coupled with the testimony of Mr. Buxton, the People support Staff's conclusion that the Commission has "reasonable grounds" to conduct a necessary audit to ensure that PGL is conducting its AMRP in the most reasonable, prudent, and efficient manner possible.

CUB-City

CUB-City initially note that most of Peoples Gas' cast iron and ductile mains were installed from the 1860s through the 1960s. Over a long period of time, cast iron and ductile iron pipes deteriorate as the pipe walls are diminished through corrosion. NS-PGL Ex. 14.0 at 7. The process of deterioration and corrosion described by the PGL's witness Phillip Hayes worsens over time, if left unremedied. Tr. at 192. The resulting soft and thin pipe walls could leak gas or rupture entirely. Tr. at. 193. Since gas is flammable, leaks or ruptures could result in fire or explosions that would be dangerous to the public. *Id.* Though PGL maintains that safety is not an issue (Tr. at 375), CUB-City aver that the safety concerns are evident from the Companies' own description of the current condition of its infrastructure. Despite the main replacement index (MRI) PGL uses to identify the pipes most in need of replacement, (PGL Ex. 14.0 at 6-7), CUB-City point out that PGL acknowledges that the MRI priorities cannot catch all pipes that may present a public danger before they actually cause harm. Tr. at 196.

CUB-City maintain that PGL is not in a position to assure the City, its customers, or the public at large that its corroded or deteriorated mains pipes do not present a public danger. Leaks or a rupture followed by fire or an explosion would undeniably be a danger to the residents of Chicago. Tr. at 193-194. CUB-City note that even Mr. Hayes could understand the City's concerns about public safety, and PGL recognizes the public safety benefits of accelerating the replacement of deteriorating and corroding mains. PGL Ex. 14.0 at 4, 7, Tr. at 194.

CUB-City explain that PGL made the decision to replace its predominantly cast iron and ductile iron main system in 1981. At that time, PGL's cast iron and ductile iron mains constituted 86% (3,450 of 4,031 miles) of the mains in the system. PGL's studies showed that main replacement was advisable. After replacing about 45 miles of mains per year, by the end of 2009, cast iron and ductile iron comprised 46% (1,870 of 4,086 miles) of the system mains. PGL Ex. 14.0 at 3-5. Looking only at the mains to be replaced, after almost thirty years PGL had replaced less than half the mains identified in 1981 as vulnerable to corrosion (1,870 of 3,450 miles).

CUB-City further explain that In 2009, PGL proposed and the Commission accepted the Accelerated Main Replacement Program ("AMRP"), which was intended to achieve an accelerated replacement of the vulnerable mains in PGL's system. After reviewing information from 2009 similar to that summarized above, the Commission concluded that "accelerated system improvement has become a matter of the public interest more so than just a Company proposal." ICC Docket No. 09-0167, Final order

of January 21, 2010 at 194. Since 2009, PGL's main replacement activity has been uneven, with only about 20 miles of mains replaced in 2009 and 2010. Activity in 2011 increased, with 155 miles of mains replaced. *Id.* at 5; *but see* NS-PGL Ex. 49.0 at 7. However, the mileage of vulnerable pipes actually removed from service is lower. Stopping the flow of gas through the pipes (de-gassing) lags installation of new pipe, because PGL's customers must be migrated to the new pipes serving them before the old pipes can be de-gassed. Due to this construction sequencing, only 19 miles of cast and ductile iron main were retired in 2011. *Id.* at 5.

CUB-City respond to PGL's statements that it plans to install approximately 360 miles of new mains and retire about 250 miles of vulnerable pipes in 2012 and 2013 by noting that that pace of replacement would exceed PGL's 2011 total of 155 miles, the most the utility has accomplished in a single year. *Id.* at 4-5. CUB-City aver that as welcome as such progress may be, PGL's commitment to that plan is only conditional -- even though an annual cost of more than $200 million is part of its proposed test year revenue requirement. PGL has not determined funding for AMRP activity beyond 2013. *Id.* at 9.

In circumstances that call for action, CUB-City say, PGL has made only a very tentative commitment to completing its replacement of these mains on the schedule approved by the Commission in PGL's 2009 rate case. CUB-City note that PGL no longer considers itself bound by its commitment to complete the main replacement program on an accelerated schedule. Tr. at 416-418. PGL's explicit position is that it is no longer committed to complete the AMRP by 2030 because its Rider ICR was declared unlawful by the Illinois Appellate Court. *Id.* The utility has actual plans to continue AMRP only through 2013, its test year. CUB-City note the fate of AMRP after that is uncertain. PGL Ex. 14.0 at 4.

In the Companies' Brief, PGL gives its perspective on the benefits of its planned AMRP effort to improve the City's utility infrastructure: "The primary benefits of replacing the cast and ductile iron main are enhancing the <u>safety</u> and <u>reliability</u> of service for customers." NS-PGL Init. Br. at 30 (emphasis added); *compare* CUB-City Init. Br. at 18-20. The City views those benefits as the most important purposes of PGL's AMRP.

CUB-City point out that PGL has already -- at this very early stage of its AMRP -- curtailed scheduled main replacements because of an apparently stronger commitment to its budgets. CUB-City note that PGL also plans to continue giving a higher priority to adhering to its budget than it will to completing the main replacements on the 20-year schedule. Tr. at 442-443. While PGL argues that "the record demonstrates that Peoples Gas has prudently managed AMRP and has made significant strides towards completing AMRP by 2030," (NS-PGL Init. Br. at 27), CUB-City maintain that this conclusion is not evident from this record. The halting course of PGL's pipe replacement activity, as the utility gives priority to other objectives, is a particular concern to CUB-City.

CUB-City also note that according to PGL's Chief Financial Officer, James Schott, whether AMRP projects continue depends on PGL's receipt of what it calls "timely and adequate" or "appropriate and timely" rate relief. Tr. at 443; NS-PGL Ex. 34.0 at 8. Mr. Schott was unable to provide a more precise measure of that precondition to accelerated main replacement. The effect, as Mr. Schott acknowledged, is that the program may continue largely at PGL's discretion.

> Q. . . . Did you have a particular level of return in mind?
>
> A. No.
>
> Q. So it would be <u>up to you</u> to determine whether it's appropriate and timely recovery?
>
> A. <u>Yes</u>. <u>We</u> would have to look at all the factors involved.

Tr. at 445 (emphasis added).

CUB-City aver that the Commission must reaffirm in the clearest possible terms that timely completion of the AMRP remains a Commission priority. CUB-City say the Commission also must consider carefully whether meeting the evident need for expeditious replacement of vulnerable pipes can be contingent on earnings criteria PGL deems wholly within its discretion. Tr. at 443-445. CUB-City disagree with PGL that safety and reliable service permit timely completion of the AMRP can be subject to a precondition -- PGL's perception of the adequacy of its profit level. CUB-City find such conditions attached to what the Commission has called a matter of public interest an unacceptable qualification on PGL's statutory obligation to maintain and operate its plant in a safe manner and to provide reliable service to its customers. 220 ILCS 5/8-101, 8-102, 8-505.

CUB-City note Staff's recommendation for an investigation and the possible result of an increased level of Commission oversight of PGL's AMRP. CUB-City's concerns embrace both PGL's public safety responsibilities and PGL's obligation to provide adequate and reliable gas utility service to City residents. *See* 220 ILCS 5/9-102. If a higher level of Commission oversight were likely to impede AMRP completion, CUB-City could not support the Staff recommendation. However, CUB-City argues PGL's evidence of an alleged adverse effect of a Commission investigation has not been persuasive.

According to PGL, it already has engaged an engineering consultant that will bring many of the benefits expected from a Commission-retained expert. NS-PGL Ex. 49.0 at 21. However, CUB-City avers the work of the utility's expert may have a focus that is less public oriented (and more aimed at utility objectives) than the assessment portion of Staff's recommended process. CUB-City agrees with Staff's proposal, which they say has prudently segmented its recommended process to require an investigation first. CUB-City believe that phase of the process may demonstrate that further Commission

involvement is not needed. However, say CUB-City, given the many miles of vulnerable pipes remaining in service, and the importance of replacing them before safety or service suffer, if the Commission finds merit in Staff's unfavorable review of PGL's AMRP efforts to date, getting a "second opinion" seems prudent.

Commission Analysis and Conclusion

Consistent with the final order in Docket No. 09-0167, this Commission remains concerned about and committed to ensuring the completion of the Accelerated Main Replacement Program. The record indicates that this 20 year program is making some progress but not as much as Peoples' projected. The record also suggests there are reasons to question Peoples' ability to complete the project in a timely and cost effective manner. The limited progress made on the Program has come at a cost much higher than Peoples' projected. The Commission, however, shares the concerns expressed by CUB-City that an investigation could impede the progress of this Program even more. Peoples has an obligation to provide a safe and reliable natural gas service to its customers. Part of its obligation is to keep this vital Program moving forward without delays or excuses. Peoples need to work with the other entities to ensure that a detailed plan, including discussions, meetings and all aspects of this project are laid out in detail. The Company also needs to do a better job of tracking the progress of this major project. This Commission expects that the information, both its Program Plan and its tracking of progress, will be presented in a clear and concise manner. The Commission believes this is the least it can expect at a time when the Company is asking for continued support for this Program. If Peoples' is unable to improve its planning and progress tracking, the Commission will have no choice but to revisit Staff's recommendation for an investigation of this Program either when the Utilities file their next rate case or perhaps, sooner.

Next the Commission must address Staff's proposed adjustments to the costs associated with the 2012 and 2013 years of the AMRP. Staff's points out that the Company has missed its targets and the proposed adjustments are based on the percentage of work that was completed by Peoples. The total amount of the recommended adjustments is $218,598,000. However, there is nothing in Staff's testimony that the costs were not incurred by Peoples for this program. There also was no showing that the costs were imprudent, not reasonably incurred nor used and useful in furtherance of the AMRP. The Commission understands Staff's concerns about the progress on this Program; however, the adjustments proposed by Staff are not supported by the record. Therefore, Staff's proposed adjustments are rejected.

c. Construction Work In Progress (PGL)

People Gas

Peoples Gas presented extensive evidence supporting its Utility Plant in Service in rate base, as referenced in Section IV.A.1, supra. Peoples Gas argues that the AG's proposed disallowance of the amount of Construction Work In Progress ("CWIP") associated with AMRP projects is improper as it rests on an incorrect legal premise and is otherwise wrong and not likely to benefit customers. First, the AG's argument that

CWIP is not "used and useful" is not applicable to this CWIP investment. *See, e.g., Citizens for a Better Env't v. Ill. Commerce Comm'n*, 103 Ill. App. 3d 133, 430 N.E.2d 684 (4th Dist. 1981) (affirming inclusion in rate base as CWIP of $97 million of investment in unfinished generating station over objection that the unfinished station was not used and useful). Peoples Gas argues that Section 9-214(e) of the Act, 220 ILCS 5/9-214(e), is specifically applicable to CWIP, and provides that "the Commission may include in the rate base of a public utility an amount for CWIP for a public utility's investment which is scheduled to be placed in service within 12 months of the date of the rate determination" without any necessity that the short-term CWIP be shown to be used and useful. Peoples Gas states that these CWIP investments will be providing service and be used and useful in 2013. NS-PGL Ex. 34.0 at 12-14; NS-PGL Ex. 49.0 Corr. at 30-32. Furthermore, no one contends that the 12-month limitation in Section 9-214(e) (*i.e.*, that the plant will be placed in service by July 2014) is not met by the CWIP in question. Peoples Gas states that AMRP is a capital intensive program that will necessarily require a large amount of costs to move in and out of CWIP as mains are gassed and placed into service. As Peoples Gas moves to the zonal approach of implementing AMRP, the execution of the installation and follow-on gassing process will be easier to manage and facilitate. This is demonstrated by the fact that the CWIP balances related to AMRP projects have been steadily decreasing from $95.9 million at September 30, 2012 to $38.1 million at December 31, 2012. NS-PGL Ex. 34.0 at 13; NS-PGL Ex. 49.0 Corr. at 31-32.

Peoples Gas argues that the AG's proposal regarding AMRP-related CWIP, as well as Staff's adjustments to rate base for 2012 and 2013 AMRP costs, are contrary to the law in each instance and punitive. As to CWIP, it is allowed under Section 9-214 and Commission precedent and there is no evidence that these facilities will not be placed in service in 2013 or as required by the Section 9-214. However, the impacts of the AG and Staff proposals if approved are severe. If approved, Peoples Gas will be unable to sustain its investments in AMRP resulting in a major loss for customers as well as in a loss of significant number of good-paying construction jobs that have already been created. NS-PGL Ex. 22.0 2nd Rev. at 2-3. This conclusion is supported by the UWUA. See UWUA Local 18007 Ex. 1.0 at 4, 6. Peoples Gas notes that if the Commission determines an adjustment is appropriate, which it should not, adopting the Staff and AG adjustments to AMRP costs would be duplicative. NS-PGL Ex. 43.0 at 14.

Staff

According to Staff, AG witness David J. Effron recommends reducing Peoples Gas' Construction Work in Progress ("CWIP") to $4,639,000 to exclude AMRP projects that will not be used and useful in providing service in the 2013 test year. AG Ex. 5.0 at 13. Mr. Effron supports his concerns about the Company's completion of projects as planned. AG Ex. at 11-12. Correspondingly, Staff recommended a reduction of Peoples Gas' rate base due to the Company's inability to provide a reasonable project plan and failure to demonstrate that it will incur the AMRP costs it projected for the test year. Staff Ex. 16.0 at 20-26. Mr. Effron's proposed adjustment may be duplicative of Staff's adjustment. NS-PGL Ex. 43.0 at 14. Since the level of duplication has not been

established, the Commission should adopt Staff's adjustment rather than Mr. Effron's, but not both.

Additionally, Mr. Effron advocates for too strict a test to determine if CWIP should be included in rate base by using December 31, 2013 as the date by which CWIP must be placed in service. AG Ex. at 12. The Act allows the Commission to *include in the rate base of a public utility an amount for CWIP for a public utility's investment which is scheduled to be placed in service within 12 months of the date of the rate determination.* 220 ILCS 5/9-214(e) (emphasis added). Mr. Effron does not offer support of an amount of CWIP that will not be in service within 12 months of the date of the rate determination; which will be approximately July 2014. The Commission should not accept the amount of Mr. Effron's adjustment unless a finding is made that none of CWIP will be placed in service within 12 months of the date of the rate determination.

AG

AG witness Effron, following a careful analysis, discovered that PGL overstated the amount of test year plant in service because the AMRP will not be placed in service on the schedule contemplated by PGL. Section 9-212 of the Act (220 ILCS 5/9-212) requires that, in order to be included in a utility's rate base, the utility must prove (and the Commission must determine) that additions to existing plant are both prudent and used and useful in providing utility service to the utility's customers. The Construction Work in Progress (CWIP) balance represents the amount of construction in progress that has not yet been placed into service, and thereby cleared, into plant in service – by its very definition CWIP cannot be used and useful. As discussed in greater detail below, ratepayers should not be forced to pay for large balances of AMRP plant that are still works in progress and not currently used and useful in the provision of utility service. The People's adjustment seeks to remedy this by reducing the average balance of test year plant in service.

The People's adjustment is reasonable because it removes a substantial balance of AMRP construction in progress from the test year plant in service. Per PGL's own data, a substantial balance of AMRP plant sat in CWIP for each month in 2012 through November. See AG Ex. 5.2 at 10, 12. This balance increased from $20.0 million in January to $100.7 million in August and then decreased somewhat, but was still $61.1 million as of November 2012. See AG Ex. 5.2 at 9, 10. This stands in sharp contrast to PGL's budgeted level of AMRP plant in CWIP as of November 2012, which was zero. AG Ex. 5.2 at 8. The net result of this is that $61.1 million of AMRP plant that the Company had originally budgeted to be in service as of November 2012 was still sitting in CWIP, and was not, in fact, in service. This makes it clear that AMRP plant is not going into service on the schedule anticipated by Peoples Gas.

Company witness Mr. Hengtgen asserts that the balance at September 30, 2012 will likely be cleared to plant in service at some point in 2013. NS-PGL Ex. 27.0 at 34. However, even if we take this highly dubious and optimistic projection as true, PGL also forecasts almost *$221 million* of spending on AMRP plant in 2013. Yet, PGL's forecasted 2013 year-end balance of CWIP is only $182,000. NS-PGL Ex. 19.2P,

Sched. B-5 at 2. Therefore, for the purpose of determining its test year rate base, PGL is implicitly assuming that substantially all of its AMRP spending in 2013 will be complete and in service by the end of the year. This assumption is not only unrealistic, it harms ratepayers by making them pay an artificially inflated rate until the next rate case.

As further evidence of the unrealistic and perhaps contradictory nature of this critical assumption, PGL stated in response to AG Data Request 14.08, that "It is expected that the [AMRP] projects in CWIP between January and August 2013 will be in service by December 2013 or early 2014." AG Ex. 5.2 at 12. Therefore, it seems as though even some of the AMRP projects commenced in the first eight months of 2013 will not be going into service until 2014.

It should be noted that PGL made no representations about the in-service timing of any AMRP plant in CWIP in the last four months of 2013 in its written testimony. However, by the Company's own admission at the evidentiary hearing, AMRP projects begun in the third quarter of 2012 were not likely to be placed into service in 2012. Tr. at 184. The Company has not yet estimated when the projects begun in the third quarter of 2013 will be placed into service, but it is likely that they will not be placed into service in 2013. Tr. at 184.

The Company's assumption would require the highly unlikely assumption that all of the AMRP projects in 2012 and 2013 will be used and useful for the 2013 test year. Based on Mr. Effron's analysis of the information provided by PGL, it is "highly unlikely" that all of the AMRP projects in 2012 and 2013 will be used and useful in providing utility service in the 2013 test year in this case. AG Ex. 5.0 at 9. Therefore, the forecast of utility plant in service in the Peoples Gas 2013 rate base should be adjusted. The AG proposal resolves PGL's unrealistic assumption that it will clear substantially all of the AMRP spending in 2013 to plant in service.

The premises upon which the People base its recommendations are far from "faulty and uninformed" as PGL witness Hentgen complains. PGL Ex. 27.0 at 33. The AG recommendation is, in fact, a very reasonable solution to the problem presented by both the inherent month-to-month fluctuation of CWIP and the Company's unrealistic assumptions. AG witness Mr. Effron analyzed the average balance of AMRP plant in CWIP for the first 11 months of 2012 and found the average to be $56,114,000, a number he deemed to be representative of the average balance of CWIP as new AMRP projects are added and completed AMRP projects are placed into service.

As further explained by Mr. Effron, PGL itself projected an average balance of $4,639,000 of CWIP in its 2013 test year rate base (NS-PGL Ex. 19.2P, Schedule B-5, Page 2), which is not unreasonable. However, the estimated average 2013 balance of AMRP plant in CWIP in excess of $4,639,000, which will not be used and useful in providing utility service in the test year, should be eliminated from the PGL test year rate base. This adjustment reduces the test plant in service included in rate base by $51,476,000 (Exhibit AG 5.1, Schedule DJE-1.3P). Net of offsetting adjustments to

depreciation reserve and accumulated deferred income taxes, the appropriate net adjustment to the PGL test year rate base is $36,284,000. *Id*. The reduction to test year plant in service results in derivative reduction to test year depreciation expense of $1,935,000. *Id*.

Therefore, the AG concludes that the Commission should adopt the AG's fair and reasonable proposal because it corrects an unfair and unrealistic projection of AMRP spending to be transferred to plant in service and the Company has not proven that its projected amounts to be placed in plant in service represent additions that are used and useful in providing utility service.

Commission Analysis and Conclusion

The AG is proposing an adjustment to the AMRP plant in CWIP in the amount of $4,639,000 because some of it will not be used and useful in the test year. Section 9-214 of the Act provides in pertinent part states, that

> Notwithstanding the provisions of paragraphs (b) and (d) of this Section, the Commission may include in the rate base of a public utility an amount for CWIP for a public utility's investment which is scheduled to be placed in service within 12 months of the date of the rate determination. . . . (220 ILCS 5/9-214(e)).

As long as there is a preponderance of evidence that the projects that are being funded by CWIP will be placed in service within 12 months from June of 2013, inclusion in rate base of CWIP-funded projects is proper. The Commission therefore disagrees with the AG's argument that AMRP-related CWIP should not be included in rate base. The Commission finds that the record indicates that CWIP will be based in service in 2013 or within 12 months of the date of the rate determination. Therefore, the Commission declines to adopt the adjustments to CWIP as recommended by the AG.

d. Non-Union Wages (see also Section V.C.2)

See Section V.C.2. (This is discussed in the Operating Expenses section)

e. Capital Costs for Non-AMRP Gas Services

People Gas

Peoples Gas states that in preparing surrebuttal testimony, Peoples Gas discovered that test year amounts for Non-AMRP Gas Services were significantly understated.[8] NS-PGL Ex. 44.0 at 10. These costs include the capital work on Peoples Gas' system that adds new services for customers for Non-AMRP projects as well as other capital replacements for existing services. For the test year, 2013, People Gas incorrectly estimated Non-AMRP Gas Services to be $4,359,396. This is demonstrated by the fact that for the last three years Non-AMRP Gas Services were: $26 million in 2010, $18.5 million in 2011, and $24.5 million in 2012. Peoples Gas proposes to

[8] Note that this item does not apply to North Shore.

increase Non-AMRP Gas Services to $16,073,896. Peoples Gas states that this amount is conservative and more reflective of its actual experience. The costs will be prudently incurred, reasonable in cost and used and useful in providing customer service. Therefore, Peoples Gas concludes that the Commission should approve this revised amount. Furthermore, Peoples Gas states that Staff and intervenors did have an opportunity to review and respond to the corrected Non-AMRP Gas Services amount as robust discovery continued after the Utilities filed surrebuttal, and the opportunity to cross examine the appropriate Utilities' witness existed at hearing. For example, the Utilities note that Staff witness Seagle reviewed Utilities witness Mr. Hoops testimony concerning the Calumet System Upgrade and agreed that the project should be included in rate base. Both discovery and cross-examination occurred. Furthermore, Staff's argument is somewhat hypocritical. Staff did not take a similar position with respect to Staff's motion for leave to file the Supplemental Rebuttal Testimony of Daniel Kahle, Staff Ex. 23.0, which revised a proposed adjustment to North Shore's Plant in Service to reflect actual 2012 data, served approximately 25 *hours* before the Utilities' surrebuttal testimony was due. Therefore, Staff and intervenors have not been precluded from reviewing such data.

Staff

According to Staff, it was not until the Company's surrebuttal did Peoples Gas witness Mr. Kyle Hoops request an increased amount for Non-AMRP gas services. Mr. Hoops claimed that Peoples Gas originally underestimated this amount and that Peoples Gas had only estimated $4,359,396 in Non-AMRP Gas Services for 2013. NS-PGL Ex. 44.0 at 9-10. Mr. Hoops then claimed that Peoples Gas incurred $26.0 million, $18.5 million, and $24.5 million, respectively, in 2010, 2011 and 2012 for Non-AMRP Gas Services, or an average of $23.0 million. *Id*. He then claimed that the Commission should allow Peoples Gas to increase its requested amount for Non-AMRP Gas Services by the amount of the reduction in the costs associated with the Calumet System Upgrade or an increase from $4,359,396 to $16,073,896." *Id*.

Staff's position is that NS/PGL could have and should have offered testimony about these costs related to the Non-AMRP gas services when it filed Direct Testimony. In fact, Peoples Gas had two additional opportunities to find its claimed "error" because Peoples Gas also filed Supplemental Direct and Rebuttal Testimony. Instead, Peoples provides no rationale for why this "error" occurred and no excuse for why it did not discover the "error" sooner.

Furthermore, the Companies' request took place when the parties of the proceeding had no time to investigate or respond to this change. As a result, NS-PGL's submission of Mr. Hoops' over $12 million increase in Non-ARMP Gas Services costs (NS-PGL Ex. 44.0 at 10 and Staff Cross Ex. 11) prejudices the parties, because they were deprived of a meaningful opportunity to investigate and respond to Mr. Hoops' testimony prior to the evidentiary hearing. Moreover, the timing of the request resulted in the parties being unable to review the request to ensure that it satisfies the Commission's requirements for a capital addition, namely that the project meets the prudence and used and usefulness standards of the PUA. For these reasons, Staff

recommends that the Commission reject Peoples Gas' request for a last minute $12,122,000 rate base and $242,000 depreciation expense increase[9].

Commission Analysis and Conclusion

The Company requested a substantial increase in the Non-AMRP services at the surrebuttal stage of testimony. It was at this time that Peoples Gas witness Mr. Kyle Hoops claims to have discovered the understatement of the amount for Non-AMRP gas services. The Companies did not provide any explanation as to why this error was not discovered sooner. The Commission agrees that parties were prejudiced when this change occurred in the surrebuttal testimony as it deprived the other parties a meaningful opportunity to investigate and respond to this change prior to the evidentiary hearing. The Commission agrees with Staff's recommendations and rejects Peoples Gas' request for a last minute $12,122,000 rate base and $242,000 depreciation expense increase.

3. Cash Working Capital

a. Pass-Through Taxes

Utilities

The Utilities explain how they believe that the Commission Order in their last rate case, Docket No. 11-0280/0281 (cons) incorrectly concluded that the revenue lag days for pass-through taxes and energy assistance charges ("EACs") should be set to zero. NS Ex. 7.0 at 25; PGL Ex. 7.0 at 27; NS-PGL Init. Br. at 41-43. In a lead-lag study, the Utilities explain that the revenue lag measures the number of days from the date service was rendered by the Utilities until the date payment was received from customers and such funds become available to the Utilities. NS Ex. 7.0 at 21; PGL Ex. 7.0 at 22. Pass-through taxes and EACs are included on the monthly bills and payments are received for these amounts at the same time as all other cash from its customers, therefore the lag for the collection of such taxes and charges is identical to the revenue lag. NS Ex. 7.0 at 23, 24; PGL Ex. 7.0 at 25, 26. Staff agrees. NS-PGL Ex. 27.0 at 16. Staff also agrees that pass-through taxes are part of the Utilities' day-to-day cash flows (cash in-flows and out-flows). Staff Ex. 2.0 at 15; NS-PGL Ex. 27.0 at 16. However, Peoples Gas states that Staff and the AG incorrectly argue that the revenue lag for pass-through taxes (except the ICC Gas Revenue Tax ("GRT")) and EACs should be set at zero. Peoples Gas concludes that the Staff and AG proposals are without merit for a number of reasons and should be rejected. NS-PGL Init. Br. at 44.

First, Peoples Gas states that Staff's and AG's position to substitute zero for the lag for pass-through taxes and EACs effectively eliminates the cash in-flow for such taxes and charges in the lead-lag study even though Staff has acknowledged that they are part of the Utilities' day-to-day in-flows. For Peoples Gas, the payment of pass-through taxes is governed by an agreement with the City of Chicago ("City Agreement"). The Utilities have demonstrated through examples for each tax and charge that they do

[9] Staff Cross Ex. 11

not hold the amounts collected as long as the Staff and AG claim. NS-PGL Ex. 27.0 at 17-22. For example, for Peoples Gas' Gross Receipts/Municipal Utility Tax ("MUT") and the City of Chicago Gas Use Tax ("City GUT"), NS-PGL Ex. 27.12P shows the possible collection dates for an example month (September 2012) and when those amounts would be due based on all of the possible collection dates in that month. The MUT and the City GUT are due by the 15th of the month following the month of collection, or in the example, October 15th. Based on the Utilities' analysis, if Peoples Gas collected all of the MUT and City GUT on September 1, 2012, the longest period of time those funds would be held (the revenue lag) is 44 days. If all the funds were collected on September 30, 2012, the longest period of time such funds would be held is 15 days. However, Peoples Gas explains that the reality is that the amounts are not collected on the first day or last day of any given month but are collected over the course of the month. Thus, on average, Peoples Gas would have access to those funds on average for 30 days. Peoples Gas' proposed lead-lag study reflects that these amounts are held for 24.2 days (MUT) and 24.31 days (City GUT). These lags are slightly lower than average discussed above as a result of the City Agreement, which governs how these taxes are paid (except for the GRT). The Utilities state that North Shore also follows this process for submitting pass through taxes (except for the GRT). However, the Staff and AG proposal reflects Peoples Gas holding those amounts for 73.79 days for the MUT and 73.90 days for the City GUT. Thus, Staff and the AG inaccurately have the Utilities holding these collected amounts longer than they actually do.

Further, Peoples Gas argues that the AG's arguments regarding the terms of the agreement with the City lack merit. The City Agreement sets forth a formula by which Peoples Gas calculates the *estimated* collection percentages for the various taxes. NS-PGL Ex. 43.0 at 18-21; NS-PGL Init. Br. at 46. Nothing in how the estimated amounts are calculated changes the fact that the pass-through taxes are to be remitted the 15th day in the month following the month of collection. *Id.* Failure to do so would result in penalties to the Utilities. *Id*. Thus, as demonstrated by their analysis and supported by the City Agreement, the Utilities' proposed lead-lag study correctly reflects the appropriate lags associated with pass-through taxes and EACs.

Second, Peoples Gas states that Staff and AG both rely on the Orders in the rate cases for other utilities, including Docket No. 08-0363, Northern Illinois Gas Company; Docket Nos. 09-0306/0307/0311 (cons.) and 11-0282, Ameren Illinois; and Docket Nos. 10-0467 and 11-0721, Commonwealth Edison Co. However, it is a factual question as to when a utility must make certain payments, such as taxes, and when it receives cash from customers to make payments, thus the decisions in other utilities' rate cases are not controlling here. NS-PGL Init. Br. at 46-47. Note that the Commission acknowledged that the determination is factual in both the Utilities' 2009 rate cases and 2011 rate cases. *Peoples Gas 2009* Order at 24; *Peoples Gas 2011* Order at 27. The Utilities acknowledge that the companies in the other dockets are utilities, a gas utility, a combination gas and electric utility, and an electric utility, respectively. NS-PGL Ex. 27.0 at 27-28. However, the Utilities argue that (1) electric utilities have some different types of taxes imposed on them or their customers with different requirements; (2) these utilities operate in different parts of the State subjecting them to different municipal utility taxes; and (3) not all utilities remit these types of taxes on the same basis. *Id*. For

example, there is no evidence that the utilities in the cited cases have similar agreements as Peoples Gas has with the City, including Commonwealth Edison Company, which operates in the City. *Id*. The Utilities note that Staff and AG also both err in stating that the Order in Docket No 11-0721 includes no lags for pass-through taxes as a lag is included for both the Illinois Excise Tax and the City of Chicago Infrastructure Tax. NS-PGL Init. Br. at 47.

The Utilities also argue that Staff incorrectly concludes that cash received from customers for pass-through taxes and energy assistance charges is not a payment for utility service, therefore, there should be no revenue lag. NS-PGL Init. Br. at 47-48. The types of pass-through taxes and EACs at issue are taxes or charges imposed by law on either the Utilities or their customers and were either collected through a separate charge prescribed by law or described within the statute as a charge for utility service. *Id.* For example, with respect to the energy assistance charge, the Utilities are required by State statute to include in their charges for utility service an amount that will be remitted to fund State programs related to energy assistance and renewable energy. 305 ILCS 20/13(e). *Id*. In particular, the statute states: "The Energy Assistance Charge assessed by electric and gas public utilities shall be considered a charge for public utility service." *Id.* The Utilities add that Staff is placing the form of how these taxes and charges are recorded in the Utilities' books and concluding that because they are not recorded as revenue the lag should be set at zero over the substance. *Id*. The amounts collected for the taxes and charges are not recorded as revenue or as expense. NS Ex. 7.0 at 23; PGL Ex. 7.0 at 25. The intent of the cash working capital analysis is to determine cash inflows and out flows and not what is recorded as revenue. NS-PGL Ex. 43.0 at 17. Furthermore, the revenue lag is comprised of a service lag, a billing lag, a collection lag and bank float, which do not vary for pass-through taxes and energy assistance charges. *Id*.

Finally, the Utilities argue that both Staff and the AG incorrectly conclude that the Utilities are merely collection agents with respect to pass-through taxes and EACs, and as such there is nothing for shareholders to finance. This argument is a red herring and must be rejected. The implication that the Utilities are requesting a positive CWC in this proceeding is incorrect. The Utilities have included in rate base a negative amount of CWC for pass-through taxes; thus, there is no customer funding. NS-PGL Ex. 27.0 at 29. Staff agrees. *Id.* Further, if the Utilities are merely collection agents and as such cash inflows should not be reflected in the lead-lag study, then it not reasonable to assume that there would be cash outflows. *Id.* In other words, the Utilities state that Staff and the AG argue that the Utilities are only collection agents when collecting the amounts for pass-through taxes but they are not collection agents when making the payments. This is not logical. If the Utilities are collection agents, then neither the collection of pass-through taxes nor the payment of such taxes should be included in the lead-lag study. The Utilities add that this assertion also ignores that the Utilities still require cash on hand to pay the tax by the due date, whether collected or not. NS-PGL Ex. 27.0 at 25.

Proposed Alternative Approach

Even though the record in this proceeding demonstrates that a lag related to pass-through taxes and EACs is proper, the Utilities have proposed an alternative approach which would allow for the lag to be set at zero for pass-through taxes (except the ICC Gas Revenue Tax) and EACs. In the proposal, the expense leads would be reduced by the same value. The alternative proposal reflects customer financing of these amounts and as such customers are benefitting through lower rate base. NS-PGL Ex. 43.0 at 23-24. Staff agrees with this alternative approach. NS-PGL Cross Ex. 1. Therefore, if the Commission rejects the Utilities' proposed revenue lags for pass-through taxes and energy assistance charges, it should adopt this alternative proposal and reflect the leads as shown on NS-PGL Ex. 43.8N and 43.8P.

Staff

The Commission should not allow a revenue lag[10] for pass-through taxes. Pass-through taxes are not operating revenues and are not included in the revenue requirement as operating revenues. The Companies' offered a proposal in their surrebuttal testimony to use zero lag days for pass-through taxes. NS-PGL Ex. 43.0 at 23, ll. 520-524. Staff accepted this proposal on cross examination. Tr. at 151-152. The AG also recommends no revenue lag for pass-through taxes. AG Ex. 1.0 at 52-54.

AG

In the Commission's *Peoples Gas 2011* Order, the Commission assigned a zero revenue lag to pass-through taxes. *Peoples Gas 2011* Order at 27. This adjustment should be made again in this docket because the Companies collect additional charges for pass-through taxes through a rider tariff and are not responsible for remittance of such taxes until after they collect revenues from ratepayers. The tariff captioned Rider 1 Additional Charges for Taxes and Customer Charge Adjustments provides for additional charges to customers where NS and PGL act as collection agents for State and local governments in the collection and remittance of taxes. This process is unique and results in pass-through taxes becoming balance sheet transactions that do not create either gas revenues or tax expenses on the Companies' income statements.[11]

Pass-through taxes are not a liability of the Companies that must be paid before taxable revenues have been collected from customers. The Illinois laws and regulations that provide for the collection and payment of pass-through taxes by the Companies indicates that such taxes are payable based upon the amounts of *collected* revenues. For example, the Illinois Gas Use Tax provided for at 35 ILCS 173/5-15 states that, "The tax collected by any delivering supplier shall constitute a debt owed by that person to this State." Similarly, the Municipal Utility Tax provided for at 65 ILCS 5/8-11-2 is a tax on "Gross Receipts" which is defined as, "…the consideration received for distributing, supplying, furnishing or selling gas for use or consumption and not for resale." The

[10] Lag times are associated with the collection of revenues owed to the Companies (that is, the collection of cash from customers' lags behind the Companies' cash outlays for the provision of service). Staff Ex. 2.0 at 13.

[11] See Part 285.315(a) at page 262 showing taxes accrued for State Public Utility, Gross Revenue, Illinois Gas Use, Municipal Utility and Chicago Sales & Use taxes with no corresponding distribution of such taxes to expense account 408, Taxes Other Than Income Tax expense.

Chicago Gas Use Tax at Chapter 3-41-050(6) of the Municipal Code of Chicago provides for Collection of Tax noting that, "The public utility shall not be liable to the city for any tax not actually collected from a retail purchaser." AG Ex. 1.0 at 53-54.

To reflect the fact that Pass-Through Taxes are not a liability that requires CWC, Mr. Brosch modified Schedule B-5 to effect proper treatment of pass-through taxes by assigning a zero revenue lag day value to the cash inflows that are associated with the Companies' collection of pass-through taxes at line 2 of Schedule B-5 in both AG Exhibit 4.3 and AG Exhibit 4.4. Both Staff witness Kahle and CUB witness Smith proposed identical adjustments.

In response to this justified modification to the Companies' CWC calculation, NS-PGL Hengtgen argued that Mr. Brosch's assignment of a zero revenue lag day value for pass-through taxes is "incorrect and illogical" and that no "analysis or quantitative support" for doing so has been provided by either Mr. Brosch or Staff witness Mr. Kahle.[12] These claims are invalid for several reasons. First, the assignment of a zero revenue lag day value is entirely correct and quite logical because these taxes are incurred because of, and at the time of, the collection of taxable revenues by the Companies. The relevant statutes and municipal codes[13] show this to be true, and the Commission endorsed that position in its recent rate Orders.[14] There is no need for "analysis or quantitative support" for utilization of zero revenue lag days because of the fact that pass-through taxes become payable when revenues have been collected by the Companies.

In fact, Mr. Hengtgen admits that pass through taxes, with the exception of the ICC Gas Revenue Tax, are due and payable upon (or after) collection, as both Mr. Brosch and Mr. Kahle assert. In response to Data Request PGL 16.21, the Companies stated, "Mr. Hentgen agrees and does not have to assume that for the pass through taxes listed on NS-PGL ex. 27.13P and 27.13N, with the exception of the ICC Gas Revenue Tax, the amounts are due and payable upon (or after) collection. These facts have been discussed and identified in Mr. Hengtgen's direct testimony and rebuttal testimony and are clearly presented in its lead lag study, WPB-8. However, Mr. Hengtgen cannot assume that 'no revenue lag is applicable'. There is a cash inflow of these funds to the Utilities, therefore there is a lag and it is identical to the lag as explained in Mr. Hengtgen's direct and rebuttal testimonies. Therefore, no modifications to the Utilities' lead day values can be calculated and is not required." That data request response appears in AG Exhibit 4.10, along with copies of the relevant pages from the referenced WPB-8 that were used by Mr. Hengtgen to calculate the pass through tax payment lead day values.

Mr. Brosch adopted and used Mr. Hengtgen's calculated pass through tax lead day values in his calculation of CWC. Mr. Hengtgen continues to support the payment lead day values he sponsored in direct testimony, while mysteriously concluding that

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12 NS-PGL Ex. 27.0 at 15.

13 AG Ex. 1.0, page 53.

14 *See,* e.g., *Peoples Gas 2011* Order at 27.

assignment of a zero revenue lag to the related customer remittances within the AG and Staff lead/lag adjustments now makes Mr. Hengtgen's payment lead day values for these taxes suddenly become unreasonable and illogical. This position makes no sense. The lead day values that were calculated by Mr. Hengtgen were reasonable for use by Mr. Brosch and by Staff in calculating the Companies' cash working capital for the test year. The calculations shown on the Companies' WPB-8 for pass-through taxes clearly show that specific revenue "collection assumptions" were used to calculate the total amounts of taxes actually paid for each month of 2011. These workpapers reflect that actual taxes paid by PGL each month relate to revenues billed in the current "service month" as well as revenues earned in three prior months, which are designated "Service Month +1", "Service Month +2" and "Service Month +3" in the workpapers. This fact causes PGL to experience longer lead days for pass through taxes than other Illinois utilities, which allows the Company to hold the cash for these pass through taxes longer than would appear to be possible under the applicable statutory payment due dates for such taxes. AG Ex. 4.0 at 58-59.

In his rebuttal testimony, however, Mr. Hentgen included new exhibits 12.12P and 12.12N for the apparent purpose of characterizing Mr. Brosch's (and Staff's) reliance upon the Companies' calculated pass through tax lead day values to be unreasonable and illogical. Mr. Hengtgen explains that his NS-PGL Ex. 27.12P shows the possible collection and due dates for Peoples Gas' Gross Receipts/Municipal Utility Tax ("MUT"), the City of Chicago Gas Use Tax ("City GUT"), the Energy Assistance Charges ("EAC") and the Gross Revenue/Public Utility Tax ("GRT"), stating "for an example month (September 2012) and when the amounts would be due based on all the possible collection dates in the example month. Mr. Hengtgen then concludes with what he calls a "side by side comparison" of the Company's calculated lead day values compared to the maximum and average number of "days held" with columns showing calculations of "Days Staff and AG Proposal Exceeds" the "Max" and "Average" of the "Days Held" derived by Mr. Hengtgen from his exhibits NS-PGL 27.12P. NS-PGL Ex. 27.0 at 22 .

This NS-PGL position is simply odd because either Mr. Hengtgen's asserted pass through tax payment lead days are reasonable, or they are not. How and when the Utilities pay pass through taxes is a factual determination without regard to measurement and application of revenue lag days to the related cash inflows. It would appear that Mr. Hengtgen is attempting in rebuttal to disparage his own calculated payment lead day values for pass through taxes, in an effort to somehow rationalize applying a full revenue lag to the related cash inflows. Mr. Hengtgen's calculations in PGL WPB-8 reveal an important difference in the timing of the Companies' actual tax remittance payments that is completely inconsistent with the assumptions now being used by Mr. Hengtgen in his rebuttal NS-PGL Ex. 27.12P. AG Ex. 4.0 at 60.

In addition, PGL does not actually pay pass through City of Chicago Gas Use Tax revenues pursuant to the "Day Collected" and "Due Date" periods shown in NS-PGL Ex. 27.12P. Actual monthly payments are based upon 25% of the current month's revenues, plus 50% of the prior month's revenues, plus 15% of the revenues from the

month before the prior month, plus 10% of the revenues from the third prior month, as shown in PGL WPB-8 for "Taxes-Pass Through-Chicago Gas Use Tax" and not the "Number of Days Held" as shown in rebuttal NS-PGL Ex. 27.12P. Mr. Hengtgen's rebuttal exhibit displays hypothetical payment patterns that are vastly different from the Company's actual remittance patterns shown in its lead lag study workpapers. The same inconsistency exists for the "Energy Assistance Charges" in NS-PGL Ex. 27.1P when compared to the "Taxes-Pass Through-EAC" analysis of actual payments in PGL WPB-8, and for "Public Utility Tax" in NS-PGL Ex. 27.1P when compared to the "Taxes-Pass Through-GRT/MUT" actual payments analyzed in PGL WPB-8. AG Ex. 4.0 at 60-61.

All of that being said, the Commission should nevertheless rely upon the payment *lead day* values sponsored by Mr. Hengtgen in his direct testimony and calculated in WPB-8 for the timing of payments of pass through taxes. As Mr. Brosch testified, this appropriate because the "Collection Assumptions" used therein are reflective of agreements made with the City of Chicago that the Companies have apparently now adopted to delay remittances of other types of pass through taxes. This distinction is referenced in Mr. Hengtgen's Rebuttal where he describes the PGL agreement (PGL Ex. 7.3) with the City of Chicago ("City"), which governs how these taxes are paid. In accordance with that agreement, Peoples Gas pays and remits the MUT and the City GUT on the basis of estimated cash receipts *regardless* of whether or not the amounts are received from customers. The estimated cash receipt percentages are based on a four-month collection period as identified on page 2 of the agreement. *See* PGL Ex. 7.3. Mr. Hengtgen used these collection percentages in his lead lag study (WPB-8, pages 45-56) in order to properly reflect the lead values as proposed by Peoples Gas. Mr. Hengtgen stated that because the agreement with the City requires the use of fixed estimated collection percentages and those percentages more than likely will differ from actual collections of these amounts from customers, the days held amount will not reflect the averages shown on NS-PGL Ex. 27.12P. Mr. Hengtgen noted that after the agreement with the City was implemented, Peoples Gas decided to use a similar process for the GRT and the EAC. North Shore also follows this process for all of its pass through taxes with the exception of the ICC Gas Revenue Tax.[15] Mr. Hengtgen should not be allowed to characterize the pass through tax "Due Dates" differently in rebuttal NS-PGL Ex. 27.1N/P so as to criticize Staff and AG, when the negotiated payment due dates that are actually employed by the Companies are much more liberal and allow more delay in tax remittances, as reflected in the referenced PGL and NS WPB-8 calculations. AG Ex. 4.0 at 61-62.

Mr. Brosch identified one needed revisions to the AG lead lag study of cash working capital in his rebuttal after review of Mr. Hengtgen's arguments. Specifically, Mr. Hengtgen states that the ICC Gas Revenue Tax is, "Different than the other pass through taxes, the ICC Gas Revenue Tax is not based on collections but 'equal to .08% of its gross revenue for each calendar year' (220 ILCS 539 5/2-202 (c))."[16] Mr. Brosch agreed with this distinction and reclassified this tax expense in AG Exhibit 4.1 and 4.2

[15] Id. page 22, lines 479-494.
[16] Id. Page 25, line 537.

near the bottom of Schedule B-5 so that it is no longer treated as a pass-through tax at lines 1 and 2. No other modifications to the AG-proposed CWC adjustments described and detailed in Mr. Brosch's testimony and exhibits are needed. AG Ex. 4.0 at 62.

Mr. Hengtgen further challenged Mr. Brosch's use of the term "lag" versus "lead" in his rebuttal, stating, "While this may seem like a minor technical point, it may be a part of the reason this issue is being contested and is confusing to people that (sic) are not familiar with 1) a lead lag study, 2) pass through taxes generally, and 3) how these cash flows (inflows and outflows) work." This condescending and and flippant suggestion that Mr. Brosch was somehow confused is unproductive. In fact, Mr. Brosch has worked with lead lag studies in multiple regulatory jurisdictions *for more than three decades.* He pointed out that the terms "lag" and "lead" can and frequently are used interchangeably by informed practitioners to reference the time difference between dates when earning or incurring a revenue or cost and the related dates of cash receipt/payment for same. Nevertheless, Mr. Brosch adopted Mr. Hengtgen's preferred terminology in this rebuttal in an effort to reduce any perceived "confusion" surrounding this matter of semantics. AG Ex. 4.0 at 63.

Mr. Hengtgen further takes issue with Mr. Brosch argument that the Utilities are only "collection agents," and asserts that the argument ignores the fact that the Utilities still require cash on hand to pay the tax by the due date because "shareholders are financing the payment until funds are collected."[17] These arguments, too, miss the mark. It is quite logical for utilities to serve as collection agents for pass through taxes through tariff Rider 1, as explained in Mr. Brosch's Direct Testimony.[18] Mr. Hengtgen's own PGL Ex. 7.3 is captioned as an "Amendment to Tax Collection Agreement" with the City of Chicago and the Companies' WPB-8 workpapers employ "Collection Assumptions" in order to calculate the relevant payment lead days for pass through taxes. In the context of ICC Gas Revenue Tax, where Mr. Hengtgen chose to dispute my "collection agent" characterization, any differences in the ratemaking treatment of cash flows has been eliminated by the modifications made to the AG calculation of cash working capital on Schedule B-5. AG Ex. 4.0 at 63-64.

In his Surrebuttal testimony, Mr. Hengtgen references again the Companies' agreement with the Cityof Chicago "to formalize and streamline this (tax collection) process" as support for his assumed collection lag related to pass through taxes. NS-PGL Ex. 43.0 at 20. But this discussion in no way clarifies the inconsistencies in Mr. Hengtgen's treatment of the pass through taxes in the lag calculations of his lead lag study and the agreement that the Company maintains with the City of Chicago. The fact remains that PGL experiences longer lead days for pass through taxes than other Illinois utilities, which allows the Company to hold the cash for these pass through taxes longer than would appear to be possible under the applicable statutory payment due dates for such taxes. Mr. Brosch's well-supported adjustment should be adopted.

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17 *Id.* at 25.

18 AG Ex. 1.0 at page 53.

CUB-City

CUB-City supports the position of AG witness Mr. Brosch and Staff witness Mr. Kahle, and, consistent with its ruling in the Companies' last rate case, urges the Commission to give pass-through taxes zero revenue lag time in the cash working capital calculation. ICC Docket 11-0280 cons. Final Order of January 10, 2012 at 52. CUB-City states this is also consistent with Commission Orders in Commonwealth Edison Company ("ComEd") Docket Nos. 10-0467 and 11-0721, 12-0321, and Ameren Illinois Company ("AIC") Docket Nos. 12-0001 and 12-0293. Staff Ex. 12.0 at 22-23, ICC Docket No. 12-0001, Final Order of September 19, 2012 at 14, ICC Docket No. 12-0293, Final Order of December 5, 2012 at 38-39.

CUB-City points out that the Commission noted in Docket No. 11-0280 cons., if money is collected from ratepayers and held prior to the payment of taxes, then it should not be included in the cash working capital requirement. ICC Docket 11-0280 cons. Final Order of January 10, 2012 at 52. CUB-City further note that the Companies admitted that pass-through taxes, with the exception of the ICC Gas Revenue Tax, are due and payable upon or after collection. AG Ex. 4.0 at 57. Mr. Brosch reclassified the ICC Gas Revenue Tax so that it was no longer treated as a pass-through tax for purposes of his adjustment. *Id*. at 62.

CUB-City explain that although Commission decisions are not *res judicata* (*City of Chicago v. Illinois Commerce Commission*, 133 Ill. App. 3d 435, 440 (1st Dist. 1985), 220 ILCS 5/10-103, 10-201(e)(iv)(A)), they are afforded deference. However, note CUB-City, Commission decisions are afforded less deference and require greater justification where they drastically depart from past Commission practice. *Business and Professional People for the Public Interest v. Illinois Commerce Comm'n*, 136 Ill. 2d 192, 228 (1989) ("BPI I"). CUB-City aver that in six of the Commission's most recent public utility rate cases, the Commission has correctly assigned zero lag days to pass-through taxes. CUB-City conclude that no facts in this record warrant a departure from this determination; thus, the Commission should remain consistent with those decisions here and assign zero revenue lag to pass-through taxes.

Commission Analysis and Conclusion

The Commission concludes that the revenue lag for pass-through taxes and EACs, except for the ICC Gas Revenue Tax, should be zero in the Utilities' lead-lag study. However, we find that the alternative approach proposed by the Utilities to reduce the expense leads as shown on NS-PGL Cross Exhibit 1 is appropriate. This approach strikes the right balance as it reflects customer financing of these amounts and as such customers are benefitting through lower rate base. Staff and the Interveners also do not object to this approach.

b. Pension/OPEB

Utilities

In their lead-lag studies, the Utilities have proposed to include a zero expense lead for Pension and Other Post-Employment Benefits ("OPEB") because to include a lead time would be duplicative since Pension and OPEB are already included in rate base. NS Ex. 7.0 at 31; PGL Ex. 7.0 at 34. The Utilities argue that Staff's argument that a lead value reflecting the intercompany billing amount be used for Pension and OPEB should be rejected. Intercompany billing payments have no relation to the cash flows related to Pension and OPEB. NS-PGL Ex. 43.0 at 24-25. The Utilities' proposal is the same recommendation made by Staff witness Mr. Kahle in Docket No. 11-0721, ComEd's 2011 formula rate case, and approved by the Commission. NS-PGL Ex. 27.0 at 31–32. The Utilities note that Staff incorrectly claims that his position in this proceeding is supported by the fact that Staff is recommending removal of the pension asset and OPEB liabilities from rate base. However, Staff is only recommending that Peoples Gas' pension asset be removed from rate base and that North Shore's pension liability, and the Utilities' OPEB liabilities be included in rate base. Further, Staff's argument that Pension and OPEB liabilities are actually driven by an operating expense component in the revenue requirement and not rate base is equally without merit. The Utilities also note that Staff witness Mr. Kahle claims that the ComEd Pension and OPEB had an operating expense component but proposed zero lead days in that proceeding. In this proceeding, he is taking an inconsistent position.

The Utilities argue that the AG's proposal that the lead value for other operations and maintenance expense be used for Pension and OPEB should also be rejected. The Utilities state that the AG proposes to use lead value for other operations and maintenance expense because it is how the Utilities schedule and pay for many types of routinely incurred expenses. However, there is nothing routine about the cash flow related to Pension and OPEB, which the AG acknowledges. NS-PGL Ex. 27.0 at 30. Further, the alternative treatment offered by the AG incorrectly subtracts from revenues associated with Pension and OPEB is incorrect as such revenues are appropriately included in the cash working capital calculation. *Id.* at 30. The Utilities note that the Commission has previously rejected the AG's proposals in both Docket No. 10-0467, ComEd's 2010 rate case, and Docket No. 11-0721.

Staff

The Commission should assign an expense lead[19] of negative 33.91 days for pension and OPEB expenses in North Shore's CWC calculation and negative 35.23 days for Peoples Gas. Staff Ex. 2.0 at 20.

Amounts included in rate base are items funded by investors on which the investors earn a return, while amounts included in CWC are expenses from the operating statement. Regardless of whether or not an amount for pensions or OPEB is

[19] Lead times are associated with the payments for goods and services received by the Companies (for example, vendors may allow the Companies to pay for goods and services after the goods and services were received). (*Id.*)

included in rate base, both items also have an operating expense component in the revenue requirement. It is the operating expense component that generates the CWC lead that Staff proposes. Staff recommends that the expense leads for inter-company billings should be used for pension and OPEB expenses in the CWC calculation. The expense leads for inter-company billings were used by the Companies for calculating CWC for pensions and OPEB expenses in their most recent rate case. Staff Ex. 2.0 at 20-21.

AG

The AG notes that Companies' Schedule B-8, at page 1, line 8 assigns a zero expense payment lead value of Pension and OPEB expenses. When the same dollars for collection of revenues associated with these expenses are assigned a full revenue lag at line 1 of Schedule B-8, the resulting CWC requirement included in rate base is significantly increased. AG witness Brosch testified that Pension and OPEB expenses are not paid currently in cash each year, such that proper lead lag study treatment of these expenses is easily determined. In order to correct this inequity, Mr. Brosch applied a more reasonable lag day value that better reflects the reality of the varied Pension and OPEB accruals.

Mr. Brosch explained that Pension and OPEB expenses are based upon accounting accruals, rather than regular and scheduled payments to vendors like other cash expenses. In responding to Staff data requests on this topic, the Companies noted that, "cash payments do not equal expense accruals recorded for Pension and OPEB."[20] These responses produced payment information for funding of OPEB amounts indicating several irregularly scheduled contributions made to an insurance plan and a single pension funding payment for North Shore but no such funding for PGL in 2011. Without more information and further analysis, it is impossible to discern a reliable payment lead day value from this data. This may be why Mr. Hentgen elected to assign a zero lag day value to Pension and OPEB expenses rather than rely upon an analysis of payment data.

Mr. Brosch testified that a reasonable treatment would be to assume the same payment lead day value the Companies have calculated for their payment of the many miscellaneous cash vouchers contained within the Other Operations and Maintenance Expense line of the lead lag study. This lead day value is indicative of how the Companies schedule and pay invoices for the many types of routinely incurred expenses that are not separately studied and listed elsewhere in the lead lag study. Notably, the Other O&M lead day value is much closer to the calculated revenue lag, which dramatically reduces the overstatement of CWC that occurs under the Companies' arbitrary assignment of a zero lead day value. AG Ex. 1.0 at 55.

He further noted that Pension and OPEB expense could be treated like all the other accrual-basis non-cash expenses such as depreciation, amortization and deferred income taxes and removed from lead lag study calculations of income taxes. This

[20] AG Ex. 4.0 at 65, citing PGL/NS responses to data requests DGK 5.02.

would be appropriate for Pension and OPEB expenses because these amounts are actuarially determined and the amount of recorded expense is dependent upon many variables, one of which is the amount and timing of contributions that are discretionary on the part of management within ranges bounded by tax and other regulations. To implement this treatment one could either subtract the Pension and OPEB expense amounts from the Line 1 revenues that are assigned a revenue lag or, alternatively, one could set the assumed payment lead for Pension and OPEB expense equal to the revenue lag day value. Either approach would have the effect of eliminating accrual-basis Pension and OPEB expenses from having any impact upon Cash Working Capital. AG Ex. 1.0 at 55-56.

In response to Mr. Brosch's analysis regarding the CWC treatment of Pension and OPEB expenses, Mr. Hengtgen argues that there is "nothing routine about the cash flow related to the Utilities Pension and OPEB expenses. Mr. Brosch even indicated in his testimony that the Utilities had supplied data in response to a staff data request reflecting irregular scheduled payments for pension and OPEB."[21] As Mr. Brosch explained in his Direct testimony, however, PGL and NS arbitrarily assumed a zero payment lead day value for pension and OPEB expenses as if there is no cash flow related to pension and OPEB expenses, causing an overstatement of cash working capital because a positive revenue lag was assigned by PGL/NS with no corresponding expense payment lead.[22] In response to Staff data request DGK 5.02, the Companies provided information showing a single pension funding for North Shore Gas in January of 2011 and no pension funding payments in 2011 for PGL. With regard to OPEB expense, the same response provided OPEB funding payments that were front-loaded in February of 2011. Using this data and assuming a calendar year analysis period would produce an exceptionally large apparent prepayment of OPEB and pension expenses for NS, and a meaningless pension lead day value for PGL since no PGL pension funding occurred. This irregular pattern of payment timing was <u>not</u> relied upon by Mr. Hengtgen in his rebuttal calculation of CWC in NS-PGL Ex. 27.10P/N and is not reliable enough for use in the AG's calculation of CWC.

A more normal pattern of cash disbursements is reflected in the Companies' analysis of miscellaneous expense payments for the line item captioned "Other Operations and Maintenance" in its lead lag study. Rather than accepting Mr. Hengtgen's arbitrarily assumed zero payment lag for pension and OPEB expenses, Mr. Brosch recommended the Other O&M lead day timing as indicative of the Companies' normal payment patterns for routine cash disbursements. Accordingly, the Commission should adopt Mr. Brosch's adjustment, detailed in my Direct testimony and in AG Ex. 4.1 and 4.2 at Schedule B-5, line 8, in column C.

CUB-City

CUB-City argue that consistent with the Commission-approved methodology used in the Companies' last rate case, Docket No. 11-0280 cons., the Commission

[21] NS-PGL Ex. 27.0 at 30.
[22] AG Ex. 1.0 at 54-55.

should include an expense lead for pension and Other Post-Employment Benefits ("OPEB"), as proposed by Mr. Brosch and Mr. Kahle. CUB-City note that Mr. Brosch proposes using the expense lead of "Other O&M" while Mr. Kahle proposes using the expense lead of "inter-company billings" lead day timing rather than the Companies' arbitrary assumption of zero payment lag days for pension and OPEB expenses. AG Ex. 4.0 at 65, Staff Ex. 12.0 at 19. Mr. Kahle's proposal, to use the expense lead days for inter-company billings, is consistent with the Companies' own methodology in their last rate case, which was adopted by the Commission. Staff Ex. 12.0 at 21. CUB has adopted Mr. Kahle's calculation as reflected in Attachments 1 and 2.

Commission Analysis and Conclusion

The Commission finds Staff's proposal that the expense leads for inter-company billing should be for pension and OPEB expenses in the CWC calculation is more appropriate and is hereby adopted. The Utilities' proposal to set lead values for Pension and OPEB at zero in the lead-lag study is not appropriate based on the evidence in the record. Staff's recommendation is consistent with the Companies' own methodology in the last rate case and this was approved by this Commission. Consistent with Staff's recommendations, the Commission assigns an expense lead of negative 33.91 days for pension and OPEB expenses in North Shore's CWC calculation and negative 35.23 days for Peoples Gas. The Commission finds that this method is more appropriate than the recommendations of the AG and the AG's proposal is rejected.

c. All Other

There are no other issues related to cash working capital

4. Retirement Benefits, Net

Utilities

The Utilities recognize that the Commission, in the Utilities' 2007, 2009, and 2011 rate cases, found that: (1) the Peoples Gas pension asset (and the North Shore pension liability) should not be included in the calculation of rate base; and (2) the Utilities' OPEB liabilities nonetheless should be included in the calculation; and, further, that the Order in their 2009 cases was affirmed on appeal on these subjects. *North Shore Gas Co., et al.*, ICC Docket Nos. 09-0166, 09-0167 Cons. (Order Jan. 21, 2010), *aff'd in part and rev'd in part*, *People ex rel. Madigan v. Illinois Commerce Comm'n*, 2011 IL App (1st) 100654, 958 N.E.2d 405 (2011), *appeal denied*, 963 N.E.2d 246 (Ill. 2012). While the Utilities agree with the Commission's past findings that, if pension assets are excluded, then pension liabilities also should be excluded, the Utilities do respectfully request that the Commission reconsider whether to include the pension asset(s) in the instant cases, and, alternatively, whether to allow recovery of specific North Shore pension contributions or exclude the OPEB liabilities. The Commission should reject Staff's proposal to exclude the Peoples Gas pension asset, but include the North Shore pension liability, if the year end rate base method is chosen.

The Utilities use the term "pension asset(s)" above because, if the end of year rate base method is used, then Peoples Gas has a pension asset and North Shore has a pension liability, while, if the average rate base method is used, then both of the Utilities have pension assets. The figures are as follows:

	End of Year Rate Base Method	**Average Rate Base Method**
Peoples Gas	Pension asset $64,662,000	Pension asset $83,705,000
North Shore	Pension liability $865,000	Pension asset $478,500

NS-PGL Ex. 31.2P at 2, line 13, col. (F) and (G); NS-PGL Ex. 31.2N at 2, line 13, col. (F) and (G).

The Commission's past decisions to exclude the Peoples Gas pension asset from rate base were based entirely on finding that the asset is, or at least has not been shown not to be, the product of customer-supplied funds. *E.g., Peoples Gas 2007* Order at 36. Staff and CUB-City advance that same position in the instant cases, while the AG simply proposes to apply the prior Commission decisions. *E.g.,* Staff Ex. 4.0 at 4; CUB-City Ex. 1.0 at 18; AG Ex. 2.0 at 12.

The Commission should reconsider approving inclusion of the pension asset(s) in rate base for several reasons. First, the premise that customers, by paying utility bills, should be treated as if they had paid for the utility's assets is incorrect as a matter of law. Customers pay for service, not for the property used to render it. *Bd. of Pub. Utility Commissioners, et al. v. New York Tel. Co.*, 271 U.S. 23 (1926). Second, the pension asset is part of the utility's balance sheet and, with respect to defined benefit plans, which is what is involved here, the utility owns the assets via the trust that holds the assets, with the employees being the beneficiaries of the trust. NS-PGL Ex. 31.0 at 12. Third, customers, by paying their bills, do not pay for the pension asset. The rates on which their bills are based reflect the accrual of pension expense. NS-PGL Ex. 31.0 at 12. Additionally, as Staff witness Ms. Pearce has acknowledged, normal operating revenues of a utility includes amounts collected through rates to repay the utility's cost of capital, and the portion of amounts collected from customers that ends up as net income is retained earnings, and thus is part of shareholder's equity, to the extent it is not paid out in dividends. PGL Ex. 11.0 at 13; NS Ex. 11.0 at 13; NS-PGL Ex. 31.0 at 13. Finally, cumulative pension contributions have exceeded cumulative recognized GAAP pension expense. NS-PGL Ex. 47.0 at 4; NS-PGL Ex. 47.1, Attachments A and B.

The Commission, in the alternative, should allow recovery on the Utilities' pension contributions in the form of payments into the trusts, specifically, the North Shore contributions of $4.0 million in 2009 and $11.1 million in 2010, which customers did not fund. Further in the alternative, the Commission could exclude the Utilities' OPEB liabilities from rate base to be consistent. PGL Ex. 11.0 at 13; NS Ex. 11.0 at 13; NS-PGL Ex. 31.0 at 14.

Finally, while Staff strongly argues for adherence to prior Orders as to exclusion of Peoples Gas' pension asset from rate base, Staff's rebuttal (Staff Ex. 14.0 at 4) inconsistently argues for subtracting the North Shore pension liability, even though that same Staff proposal was rejected in the prior Orders. More specifically, Staff made the same proposal in the Utilities' 2009 rate cases, and the *Peoples Gas 2009* Order (at at 36-37) rejected it, just as had occurred in the Utilities' 2007 rate cases, and Staff has not provided any change in circumstances or really any basis for a different outcome here. NS-PGL Ex. 47.0 at 3. Even CUB-City's witness opposes inclusion of the North Short pension liability in the rate base calculation if the Peoples Gas pension asset is excluded. CUB-City Ex. 2.0 at 49.

Accordingly, the Commission (1) should approve the inclusion of the pension asset(s) in rate base, or (2) should adopt one of the two alternative positions of the Utilities, but (3) should not adopt the Staff proposal to exclude the Peoples Gas pension asset but include the North Shore pension liability (again recognizing that North Shore has a pension liability only in the event year-end rate base is used).

Staff

The Commission should accept Staff witness Pearce's (Staff Ex. 4.0, Scheds. 4.01 N and P) and Intervenor witnesses Effron's (Ex. AG 2.1, Scheds. DJE-1 N and P) and Smith's (CUB-City Ex. 1.2 at 11; CUB-City Ex. 1.3 at 11) proposed adjustments to remove the Companies' alleged "pension asset," net of related ADIT, from rate base for the reasons explained below. The Companies presented the alleged "pension asset" net of the OPEB liability on a single schedule identified as "Retirement Benefits, Net." Staff and Intervenors did not include the OPEB liability in their adjustments. Accordingly, those parties correctly left the OPEB liability unadjusted, as a reduction to rate base.

Peoples Gas argued in rebuttal (NS-PGL Ex. 31.0 at 3) and surrebuttal (NS-PGL Ex. 47.0 at 2) testimony that the Retirement Benefits, Net should remain in rate base, whether or not a year-end or average rate base methodology is approved by the Commission. Alternatively, the Companies propose that if the Peoples Gas' alleged pension asset is excluded from rate base, and North Shore Gas has a pension liability because the year-end methodology is used, the pension liability should also be excluded from rate base and not as a reduction to rate base. NS-PGL Ex. 47.0 at 2.

The alleged "pension asset" was created with funds supplied by ratepayers, not shareholders. Therefore, shareholders are not entitled to earn a return on it.

The Companies incorrectly allege that they have a "pension asset" that should be included in rate base. The argument should be rejected because the amount that the Companies allege to be a "pension asset" was not created with funds supplied by shareholders. Instead, they represent amounts from normal operating revenues collected or to be collected from utility rate payers. 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 Commission,* 19 Ill. 2d 76, 85-6 and 91 (1960); *DuPage Utility Co. v. Illinois Commerce Commission*, 47 Ill. 2d 550, 554 and 558 (1971); and *Central Illinois Light Co. v. Illinois Commerce Commission*, 252 Ill. App. 3d 577, 583-3 (3rd Dist., 1993). See also *BPI II* at 146 Ill. 2d 175, 258. Since the alleged "pension asset" is funded by normal operations, rather than provided by discrete shareholder contributions, shareholders should not earn a return on it. Staff Ex. 4.0 at 4.

The Companies aver that the utility owns the alleged "pension asset" and the assets in the pension trust fund. However, it is not important who owns the assets in the pension trust fund. The important question is whether the alleged "pension asset" was created with funds from shareholders. Ownership is not determinative of ratemaking treatment as the above listed cases of *City of Alton v. Illinois Commerce Comm'n*,; *Dupage Utility Co. v. Illinois Commerce Comm'n*,; and *Central Illinois Light Co. v. Illinois Commerce Comm'n*, establish. As Staff witness Pearce explained in rebuttal testimony (Staff Ex. 14.0 at 5), Peoples Gas owns the entire Compressed Natural Gas ("CNG") fueling station, but because it was constructed in part using funds from a federal Clean Cities grant administered by the City of Chicago, the Company may not include in its rate base the entire cost of the CNG fueling Station. In fact, the Company only sought to include in rate base the cost of the fueling station not covered by the federal grant. NS-PGL Ex. 44.0 at 1. Therefore, even if Peoples Gas or North Shore Gas owns the alleged "pension asset," and owns the assets in the pension trust fund, which Staff does not concede, it is simply not relevant to determining whether the alleged "pension asset" should be included in rate base. Staff Ex. 14.0 at 5-6.

Moreover, Peoples Gas' and North Shore Gas' pension trust fund has an unfunded liability as of December 31, 2013 (i.e., the projected benefit obligation exceeds the balance of the assets in the pension trust). Despite having a pension liability, however, the Companies allege to have a "pension asset" by arbitrarily adding to that pension liability a *regulatory asset* (see Line 2 of table below) whose amount far exceeds the pension liability.

Line	**Avg. Balance in Thousands**[23]	**Peoples Gas RTTY**	**North Shore RTTY**
1	Net Pension Funded Status Asset/(Liability)	($279,417)	($24,871)
2	Regulatory Asset/(Liability)	363,122	25,349
3	Total Pension Asset/(Liability)	$83,705	$478

[23] NS-PGL Ex. 27.6 N and P, lines 5, 10 and 11, column (D).

The Companies' regulatory asset associated with the pension plans reflects the assured future recovery from ratepayers of the underlying pension costs through utility rates. Hence, these pension costs will be paid for by ratepayers, not shareholders. It is counterintuitive and unreasonable to require ratepayers to provide a return to shareholders for a regulatory asset that only exists because ratepayers are responsible for providing recovery of the underlying expense. Staff Ex. 4.0 at 8.

Without the inclusion of this regulatory asset that clearly represents funds to be supplied by ratepayers in the future, Peoples Gas' alleged "pension asset" would disappear. Staff Ex. 14.0 at 6-7. This would occur because, as Companies witness Ms. Phillips herself recognized, Peoples Gas' pension fund is underfunded, resulting in a pension liability and not a pension asset. NS-PGL Ex. 31.2P, line 5, columns (F) and (G). This is true whether Peoples Gas' proposed year-end rate base or Staff's proposed average rate base is adopted.

North Shore Gas did not seek to include a pension asset in its rebuttal rate base because North Shore's December 31, 2013 balance for pension costs reflects a pension liability, not an asset (that is, it is also underfunded). Under the year-end rate base proposed by North Shore, applying the "pension asset" calculation used by Peoples Gas (i.e., netting the pension liability with the regulatory asset) does not result in a positive amount that North Shore could claim as a "pension asset." Staff Ex. 14.0 at 13 - 14. Thus, no adjustment is required under that scenario. Therefore, Staff proposes no adjustment to remove the North Shore pension liability if a year-end rate base methodology is approved. However, Staff witness Daniel G. Kahle proposes the use of an average rate base for the 2013 test year. Staff Ex. 12.0. If an average rate base were adopted for North Shore and the same arguments and calculations proffered by Peoples Gas were applied, the Companies' schedules allege that North Shore would also have a "pension asset". Ex. NS-PGL Ex. 31.2 N, line 13, column (G). Therefore, Staff proposes to remove this amount, net of ADIT. Staff Ex.14.0, Sched. 14.01 N.

As noted above, it is unreasonable to net the pension liability with a regulatory asset that reflects the recognition of assured future recovery from ratepayers of the pension expense. This novel treatment leads to the absurd result of making ratepayers pay utility shareholders a return on amounts that ratepayers will pay the utility in the future. Staff Ex. 14.0 at 7-9.

The Companies have never established that the so-called "pension asset" was not created with funds collected from or to be collected from ratepayers. It is an uncontested fact that ratepayers pay for ongoing, periodic pension expense and other post-retirement benefits—not the shareholders. The Companies admit this fact. *Id.* In its reply brief Staff responded to the Utilities argument that the premise that customers, by paying utility bills, should be treated as if they had paid for the utility's assets is incorrect *as a matter of law*.

Staff pointed out that once again the Companies resort to an eighty-five year old case, *Bd. Of Pub. Utility Commissioners, et al. v. New York Tel. Co*., 271 U.S. 23

(1926), to support their position and that the Commission considered this same eighty-five year old case and rejected the same argument in the Companies' last rate cases in Docket Nos. 11-0280/0281 (Cons.[24]) and should do so again here. The case cited by the Companies, *Bd. Of Pub. Utility Commissioners,* is essentially a retroactive ratemaking case which 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. According to Staff 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 BPI II* at 146 Ill. 2d 175, 258. Staff Witness Pearce testified that the Companies failed to show that the "pension asset" was provided by discrete shareholder contributions and, as a result, "[t]he pension asset should not be included in rate base because it was not created with funds supplied by shareholders." Staff Ex. 4.0 at 4.

Accordingly, the Commission should adopt Staff's proposal to remove the alleged "pension asset" from the Companies' rate base regardless of whether a year end or average rate base is adopted. In so doing, the Commission is appropriately rejecting the novel argument that ratepayers today should be forced to pay utility shareholders a return on amounts that ratepayers will pay the utility in the future.

The Companies' assessment of past pension contributions' impact on ratepayers is not accurate.

The Companies' assertion that pension contributions exceeded expense by $77,546,609 during the period October 1, 1995 – December 31, 2013 is not an accurate assessment of the impact on ratepayers. The $77,546,609 difference between total pension expense of ($24,080,194) and total pension contributions of $53,466,415 for the 18-year period (1995 – 2013) (Staff Ex. 14.0, Att. A, at 7) is due to negative amounts of pension expense in the years 1996 – 2003. Negative pension expense typically results when the expected return on plan assets exceeds other elements that make up pension expense. In other words, earnings on the pension assets exceeded pension costs during these periods; however, ratepayers did not receive the benefit of these negative expenses. In order for ratepayers to receive a direct benefit from these negative expenses, a rate case would have had to be filed that reflected the negative amounts in the revenue requirement. Peoples Gas did not seek a change in rates between 1995 and 2007 (i.e., Docket No. 95-0032 and Docket No. 07-0242). Therefore, the negative expense amounts have **not** been reflected in past utility rates. Moreover, Peoples Gas filed several rate cases since its rate case in Docket No. 95-0032. As shown in the table below, in the overwhelming majority of these rate cases, the Companies' pension expenses recovered from ratepayers through base rates exceeded actual pension contributions—the reverse of what the Companies claim. Staff

[24] Order, Docket No. 11-0280/0281 (Cons.), January 10, 2012, p. 30

Ex. 14.0 at 11. On a total basis, pension expense of $84,257,459 exceeds pension contribution of $17,164,995 by $67,092,464. In terms of magnitude, total pension expense is almost five times greater than the pension contributions.

General Rate Case	Test Year	Pension Expense	Pension Contribution
Docket No. 07-0242	Historic test year ended 9/30/06	$ 11,507,532	$ 16,207,282
Docket No. 09-0167	Future test year ended 12/31/10	$ 8,015,677	$ 121,123
Docket No. 11-0281	Future test year ended 12/31/12	$ 26,311,141	$ 499,673
Docket No. 12-0512	Future test year ending 12/31/13	$ 38,423,109	$ 336,917
Total		**$ 84,257,459**	**$ 17,164,995**

Source: Companies Response to DR BAP 23.01, Staff Ex. 14.0, Att. A.

Shareholders did not provide a higher level of contributions than the amount of pension expense that was reflected in rates in three of the four years shown above. Further, ratepayers did not directly benefit from a reduction in pension expense during the years that the pension fund was earning returns higher than was expected because the Company did not seek a change in rates during that period. The table above supports Staff's contention that ratepayers-- not shareholders-- have supplied the funds and will continue to supply the funds for employee pension benefits. The Commission should reject this unsubstantiated and highly inaccurate claim that the Companies have used to justify inclusion of the alleged "pension asset" in rate base.

The Commission has repeatedly rejected the Companies' arguments in the past and should do so again.

The Commission has rejected the Companies' position that the pension asset should be included in rate base in the previous three rate cases[25] filed by the Companies and the Illinois Appellate Court has upheld the Commission's final order in Docket Nos. 09-0166/09-0167 (Cons.). The Companies acknowledge the fact that the Commission, in the three previously filed rate cases, has rejected their claims that an alleged "pension asset" should be included in the test year rate base. Nonetheless, in spite of the three prior Commission orders rejecting the Companies' position, as well as

[25] The three previous rate cases are: Docket Nos. 07-0241/0242 (Cons.), Docket Nos. 09-0166/0167 (Cons.) and Docket Nos. 11-0280/0281 (Cons.) Docket Nos. 11-0280/0281 (Cons.) is still pending on appeal. The appeal of Docket Nos. 07-0241/0242 was dismissed as being moot on June 20, 2012.

a ruling from the Illinois Appellate Court doing the same, the Companies continue to assert an alleged "pension asset" should be included in rate base. Staff Ex. 4.0 at 9-10. The Illinois Appellate Court upheld the Commission's January 22, 2010 Order in Docket No. 09-0166/09-0167 (Cons.). The Illinois Appellate Court stated:

> The central issue before us remains whether the Commission's decision to exclude the pension asset, which it found consisted of consumer-supplied funds, from Peoples Gas' rate base was against the manifest weight of the evidence. Both the Staff's and the People's expert witness testified the pension asset constituted customer-supplied revenues and, therefore, should be deducted from the rate base calculation.
>
> Although Peoples Gas' expert witness obviously disagreed with that assessment and testified the pension asset was generated solely from shareholder revenue, we note the credibility of expert witnesses and the weight to be given their testimony are generally matters for the Commission to determine as the finder of fact. See *Lefton Iron & Metal Co. v. Illinois Commerce Comm'n,* 174 Ill. App. 3d 1049, 1060 (1988). "Decisions of the Commission are entitled to great deference because they arise out of the deliberations of members who are much better qualified to interpret evidence supplied by specialists and technicians." *Id*. Accordingly, we must refrain from reevaluating the credibility or weight of the evidence, or from substituting our judgment for that of the Commission unless the Commission's judgment was clearly against the manifest weight of the evidence. See *Commonwealth Edison Co.*, 398 Ill. App. 3d at 514.
>
> Based on the record before us, we find the *Commission's decision with regard to the pension asset deduction is not clearly against the manifest weight of the evidence. Accordingly, we see no reason to disturb the Commission's findings*

Peoples v. Illinois Commerce Commission, Nos. 1-10-0654, 1-10-0655, 1-10-0936, 1-10-179, and 1-10-1846 and 1-10-1852, Consolidated, Appellate Court (First District-Fifth Division) September 30, 2011, at 42-43, par. 69-71 (emphasis added); Staff Ex. 4.0 at 9-10.

The Companies have presented no new facts or evidence in the instant proceeding that would warrant a different conclusion from the Commission in this proceeding than it has reached in its order for the previous three rate cases one of which, 09-0166/0167 (Cons.) was upheld on appeal as discussed above. *Id*.

AG

In his direct testimony, the People's witness Mr. Effron made an appropriate adjustment to rate base to account for net retirement benefits, and updated those adjustments in his rebuttal testimony after reviewing the rebuttal testimonies of NS/PGL witnesses Hentgen and Phillips. AG Ex. 2.0 at 12-13; AG Ex. 5.0 at 3; AG Ex. 2.1. As Mr. Effron explained in his direct testimony, net retirement benefits are comprised of two

components: prepaid pension asset – or the effect of pension fund contributions in excess of pension costs – and the accrued liability for future post-retirement benefits other than pensions ("OPEB"). The People, in line with the findings of several past Commission orders as well as testimony presented by Staff Witness Pearce and CUB-City Witness Smith, propose eliminating pension balances from rate base, treating the accrued liability for post-retirement benefits as rate base deductions, and eliminating the accumulated deferred income taxes related to prepaid or accrued pensions.

The People's adjustments are directly supported by the Commission's findings in ICC dockets 07-0241/07-0242, 09-0166/09-0167, and 11-0280/11-0281 on the appropriate treatment of the Companies' retirement benefits as part of rate base. As reflected in these decisions the Commission has routinely concluded that accrued OPEB liability should be reflected in rate base but that the pension balances should not be recognized in the determination of rate base. This notion was explicitly stated by the Commission in its Final Order in 11-0280/11-0281:

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

ICC Docket Nos. 11-0280/11-0281, Final Order (January 10, 2012) at 33. Similarly, in 09-0166/09-0167, the Commission disallowed a similar proposal by the Companies to include pension in rate base, noting that :

> The Commission finds no support in the record to allow for the inclusion of Peoples Gas' pension asset in rate base which in turn would allow shareholders to earn a return on ratepayer supplied funds.

ICC Docket Nos. 09-0166/09-0167, Final Order (January 21, 2010) at 36.

Staff witness Pearce and CUB-City witness Smith both agree with Effron's approach, and similarly removed the Companies' respective net pension assets from rate base, but kept the OPEB liabilities in rate base. *See, generally,* ICC Staff Ex. 14.0 at 3, ICC Staff Schedules 14.1N, 14.1P; CUB-City Ex. 1.0 at 18-22. The People support, and incorporate by reference, Staff's and CUB-City's arguments on this issue.

The People's proposed adjustment reduces PGL's "Retirement Benefits, Net" by $83,706,000 and related ADIT by $33,269,000, resulting in a net reduction to the PGL rate base of $50,347,000. AG Ex. 5.1, Schedule DJE-1P. The adjustment applicable to

NS reduces "Retirement Benefits, Net" by $1,841,000 and the related ADIT by $732,000, which results in a net reduction to the NS rate base of $1,109,000. AG Ex. 2.0 at 12-3, AG Ex. 2.1, Schedule DJE-1N. Mr. Effron's adjustments are consistent with the Commission's policy on this issue and the Commission should adopt them.

CUB-City

CUB-City argue that the Companies' pension assets should be removed from rate base, consistent with recent Commission practice. CUB-City note this same issue has been addressed in the Companies' last three rate cases. In each case, say CUB-City, the Commission did not allow the proposed inclusion of a pension asset in rate base and shareholder earnings on such ratepayer-supplied funds. The pension asset in this case (as in the previous cases) was not funded with investor-supplied funds. CUB-City Ex. 1.0 at 18. CUB-City aver the Companies have not shown any difference in the facts in the instant record and have not advanced any new reason for a change in this Commission policy. *Id*. at 19, 21.

CUB-City explain that in the Companies' most recent rate case, Docket No. 11-0280 cons., the Commission adopted Staff's position to remove the Companies' pension asset and associated ADIT from rate base because the pension asset was created with funds provided by ratepayers. ICC Docket 11-0280 cons., Final Order of January 10, 2012 at 32-33 ("Staff and GCI's adjustments are supported by the evidence and remain consistent with the Commission's conclusions about the pension asset in the 2007 and 2009 PGL rate cases.").

CUB-City acknowledge that Commission decisions are not *res judicata*, and the Commission must decide this case on the evidence in the record. *City of Chicago v. Illinois Commerce Commission*, 133 Ill. App. 3d 435, 440 (1st Dist. 1985), 220 ILCS 5/10-103, 10-201(e)(iv)(A). However, note CUB-City, the Commission should give its own decisions the same deference they are given by courts on appeal. In addition, Commission decisions are afforded less deference and require greater justification where they drastically depart from past Commission practice. *BPI I* at 228 (1989). CUB-City say that to decide this issue in a manner different than it was decided in the Companies' previous three rate cases, where the facts are substantially the same, would be a drastic departure and would reasonably require factual and policy bases for change that have not been provided in this record. CUB-City Ex. 2.0 at 49.

CUB-City point to NS-PGL's admission that in their last three rate cases, the Commission has disallowed their pension asset from inclusion in rate base, but request reconsideration of that position in the present case. NS-PGL Init. Br. at 51-52. CUB-City note that NS/PGL base their request on five particular points, listed on pages 53-54 of their Initial Brief. However, say CUB-City, the Companies admit that four of those five points have been raised and considered by the Commission in previous cases where the pension asset was disallowed. *Id*. at 54. While the Companies claim to have presented new data (in surrebuttal) to support one single fact (that cumulative pension contributions have exceeded Generally Accepted Accounting Principles ("GAAP")

pension expense)—"although somewhat similar points sometimes were made" in prior cases (*see Id*. at 53-54), CUB-City maintains that in reality, no new facts were presented that justify a decision to deviate from the Commission's regular practice of disallowing a pension asset. CUB-City aver that the Commission's previous, well-reasoned decisions should again provide guidance here, and the pension asset should be removed from rate base. Shareholders should not earn a return on these ratepayer-supplied funds.

CUB-City note that the Companies revised their amounts related to the pension asset that they are requesting to be included in rate base. As described in NS-PGL Ex. 31.0, page 7, for Peoples Gas:

> For the 2013 test year, the initial filing reflected an accrued pension liability of $207,826,000 with a related regulatory asset of $280,441,000; reflecting a net pension asset of $72,615,000. The updated forecasted balances for the 2013 test year are an accrued pension liability of $287,875,000 with a related regulatory asset of $352,537,000; reflecting a net pension asset of $64,662,000, a net decrease of $7,953,000.

Similarly, as described at NS-PGL Ex. 31.0, page 7, for North Shore:

> For the 2013 test year, the initial filing reflected an accrued pension liability of $15,945,000 with a related regulatory asset of $17,821,000; reflecting a net pension asset of $1,876,000. The updated forecasted balances for 2013 are an accrued pension liability of $24,999,000 with a related regulatory asset of $24,134,000; reflecting a net pension liability of $865,000, a net decrease of $2,741,000.

CUB-City note that they, Staff and AG have all made similar recommendations that no pension asset be included in rate base. Consistent with the Commission's rulings in previous Peoples Gas rate cases including Docket No. 11-0280 (cons.), CUB-City argue the pension asset should be removed from rate base for various reasons, including the fact that it has not been funded by investors. 220 ILCS 5/9-211. CUB-City aver that the adjustment to remove the pension asset should be updated to incorporate the Companies' revised amount of $64.662 million. Similarly, consistent with the Commission's rulings in previous North Shore rate cases including Docket No. 11-0280 (cons.), where the facts were essentially the same or extremely similar, CUB-City recommend the net pension asset should be removed from rate base. CUB-City say the adjustment to remove the net pension asset should be updated to incorporate the North Shore's revised amounts which net to an $865,000 pension liability.

Commission Analysis and Conclusion

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

5. Net Operating Losses

Utilities

The Utilities state that they are included in the consolidated United States income tax return filed by Integrys. NS Ex. 5.1, Schedule G-5 at 4; PGL Ex. 5.1, Schedule G-5 at 4. In its direct filing, the Utilities indicated that using their best estimates neither 2012 nor 2013 would result in a Net Operating Loss ("NOL") on a consolidated basis, even though each utility may be in a NOL position on a standalone basis. *Id.* In fact under "Summary of Significant Assumptions/Items" in Schedule G-5, the Utilities state:

> There is currently no forecasted net operating loss ("NOL") deferred income tax asset. This results from the assumption that while [the Utilities] may be generating taxable losses, the consolidated group is assumed to be able to use those losses. Under the Companies tax sharing agreement, [the Utilities] will be paid cash for the tax benefit of its loss, if any, generated on a standalone basis, and used to reduce consolidated tax obligations. [The Utilities] will therefore not have a deferred income tax asset for the NOL. This assumption will be monitored / updated at each step in the case.

NS Ex. 5.1, Schedule G-5 at 10; PGL Ex. 5.1, Schedule G-5 at 10-11. As indicated in their Schedules G-5, the Utilities did evaluate at each step. They noted in rebuttal testimony that even though Peoples Gas was now in a NOL position for 2011 and 2012, no deferred tax asset existed for 2012 or 2013 because the consolidated group's income was forecasted to absorb those losses. NS-PGL Ex. 30.0 Rev. at 27, 28. See also Staff Cross Ex. 13. However, prior to when surrebuttal testimony was filed, two major events occurred: (1) the American Taxpayer Relief Act of 2012 was enacted in January 2013; and (2) end of year 2012 books closed. The consequences of American Taxpayer Relief Act of 2012 led to NOLs for 2013 due to the election for bonus depreciation. The closing of the books for 2012 resulted in the consolidated group being in a NOL position for 2012. NS-PGL Ex. 46.0 at 36. As such, NOLs for 2012 and 2013 should *both* be included in rate base.

In response to CUB-City arguments, the Utilities state that as indicated in their Schedule G-5, forecasts are subject to change. This is why the Utilities indicated in Schedule G-5 that no NOL was being forecasted but would be monitored at every step of the case. There is no inconsistency with the position taken here with the position in the Utilities 2011 rate case. Further, the Utilities state that CUB-City arguments that 2012 NOLs were known for months shows a fundamental misunderstanding on how a

consolidated group files a tax return. The Utilities are included in the consolidated United States income tax return filed by Integrys. To the extent that the consolidated group can absorb the NOL of Peoples Gas and North Shore, no NOL is needed to be reflected in rate base. CUB-City would have the Utilities include the effects of NOLs in rate base when information available at the time would indicate it would be improper to do so.

Also, the Utilities state that the AG's argument, regarding Section 287.30 of the Commission rules, 83 Ill. Adm. Code § 287.30, is equally without merit and inconsistent with the AG's own position on 2013 bonus depreciation. While the language of Section 287.30 is unclear, the Utilities' understanding, based on the language of Section 287.30 and the absence of invocation of Section 287.30 in their previous rate cases using future test years, in brief, is to prohibit more than one across the board update (perhaps also including a major update resulting in major changes) to a utility's revenue requirement during a future test year rate case. It is not to prevent the use of new data in isolated instances, and as to updating of individual items it only has a specific provision regarding updating the rate of return. In fact, Staff has used actual year-end 2012 data to update one of its adjustments. The AG has not cited any past rulings that support the application of Section 287.30 as the AG proposes. In contrast, updates in surrebuttal are routine. Even assuming that Section 287.30 somehow were to be applied in the novel manner that the AG now proposes to an individual item update in surrebuttal, the rule would not support the AG's argument. With respect to Section 287.30(b)(2), it was *unknown* to the Utilities at the time of their initial filing and rebuttal filing that 2012 consolidated NOLs as of year-end would exist. All facts known to the Utilities indicated that the Integrys consolidated group would be able to absorb the Utilities' NOLs – Utilities' testimony, schedules, and data request responses support this fact. Second, with respect to Section 287.30(b)(3), Staff and intervenors did have an opportunity to review the 2012 NOLs. There was robust discovery in these consolidated proceedings, which continued after the filing of the surrebuttal testimony. Thus, Staff and intervenors have not been precluded from reviewing such data or unfairly prejudiced. Moreover, if the AG's proposition were true, then, for example, the inclusion of 2013 bonus depreciation to reduce rate base in the Utilities' surrebuttal, based on the recent change in law, should be equally barred. Finally, the Utilities do not believe that Section 287.30 is intended to or can override the Utilities' right to provide proper surrebuttal evidence, which was established in the case.

Finally, the Utilities state that failure to reflect a known 2012 or 2013 NOL in rate base in this proceeding may cause a violation of the normalization rules. The normalization rules for tax purposes address how a company must normalize the effect of accelerated depreciation. NS-PGL Ex. 30.0 Rev. at 30. By recording the effects of an NOL as a deferred tax asset, the tax benefit associated with accelerated depreciation is effectively eliminated until the time the loss is realized. *Id.* at 33. The result of violating this rule is severe to both the Utilities and their customers. A violation would result in the Utilities not being able to claim the rate base-reducing impacts of accelerated and bonus depreciation. *Id.*; Tr. at 777. The consequences of violating the normalization rules are unrebutted. Thus, if either the 2012 or the 2013 NOL is

excluded from rate base, the Commission should also remove 2013 bonus depreciation from the computation of ADIT.

Staff

The Companies indicated in their responses to certain Staff Data Requests ("DR"s) that they would address the impact of tax legislation that was enacted on January 2, 2013, including possibility of a Net Operating Loss ("NOL") in surrebuttal testimony. Staff Ex. 14.0 at 23. The Companies filed surrebuttal testimony on January 25, 2013 that reflects the impact of a NOL on the 2013 test year operating statement (NS-PGL Ex. 42.0) and rate base (NS-PGL Ex. 43.0) but does not incorporate the effect of the revenue increase on such NOL. Accordingly, the revenue requirements attached to Staff's Initial Brief contain two sets of adjustments to reflect the impact of Staff's proposed increase:

1) Operating Statement adjustments to reflect that Staff's proposed revenue increase results in a lower NOL and reduces the current tax provision, while increasing the deferred tax expense; and,

2) Rate Base adjustments to reflect that Staff's proposed revenue increase results in a lower NOL and reduces the ADIT asset, but not below zero, as in the case of North Shore Gas. This impact was confirmed by Companies' witness Ms. Moy during Staff's cross examination. Tr. at 706.

Staff Cross Exhibit 4[26] was entered into the evidentiary record to more fully describe the relationship of the NOL to the current and deferred tax expenses in the final revenue requirement that is approved by the Commission in this proceeding. Staff Cross Exhibit No. 10[27] was also entered into the evidentiary record to more fully describe the relationship of the NOL to the ADIT asset.

Accordingly, Staff adjusted the revenue requirements attached to this Initial Brief to reflect a lower ADIT asset in the test year rate base.

Companies' witness Stabile also confirmed that if the 2012 NOL is not included in the beginning balance for the 2013 NOL, then this would be a violation of Federal Income Tax normalization rules which would result in the loss of accelerated depreciation, including bonus depreciation. Tr. at 777.

Therefore, the Commission should reflect derivative NOL adjustments in the final operating statement and rate base schedules for the Companies based on the amount of revenue increase that is ultimately approved in this proceeding. It is Staff's understanding that the methodology to reflect the impact of the revenue increase on the NOL and final revenue requirements is not contested between Staff and the Companies.

[26] Staff DR BAP 26.02.
[27] Response to Staff DR BAP 26.01.

AG

Under Section 9-201 of the Act, a utility filing for a rate increase has the burden of proving its rates are just and reasonable. 220 ILCS 5/9-201. For the first time in this docket, the Companies in their surrebuttal testimony propose a substantial Net Operating Loss ("NOL") for 2012 that significantly increases the Companies' rate base. The adjustment, as discussed *infra*, is unexplained by the Companies' witnesses. NS and PGL failed to provide substantial evidence to demonstrate that the adjustment is necessary or reasonable. The Commission should reject the adjustment because the source and the details surrounding the 2012 NOL is conspicuously absent from the Companies' evidentiary presentation.

NS-PGL witness John Stabile discusses the American Taxpayer Relief Act of 2012, which extended the availability of 50% bonus depreciation into 2013, in his surrebuttal testimony. NS-PGL Ex. 46.0 at 34-35. At the conclusion of that discussion, he briefly notes that because of the bonus depreciation updates in 2013, the Companies are now incurring losses in 2013.[28] Then, without further detail, except a reference to Mr. Hengtgen's surrebuttal discussion, Mr. Stabile, referring to 2012, states, "In addition, based up on the status of year-end closing, the consolidated group is also in an NOL position." *Id.* at 36. No further detail is provided.

NS/PGL witness Hengtgen testified in surrebuttal testimony that he was presenting new stand-alone Net Operating Loss amounts for 2013 *and 2012* at "present rates information." NS-PGL Ex. 43.0 at 26. NS-PGL Ex. 43.2 at page 2 reflects these new ratemaking adjustments. This was the first time the Company suggested or proposed an NOL adjustment for 2012, which is unrelated to the 2013 bonus depreciation extension. Again, the details provided by the Companies for the sudden change in the 2012 NOL status are sparse, to say the least. Mr. Hengtgen's testimony states:

> **B. Net Operating Loss ("NOL")**
>
> **Q. Have the Utilities included an amount for their NOL in rate base?**
>
> A. Yes, Utilities witness Mr. Stabile discusses in his surrebuttal testimony the reason for and the amounts of NOLs that the Utilities have included in rate base.
>
> **Q. Have the Utilities reflected the NOLs at present or proposed rates?**
>
> A. The Utilities have reflected the NOLs at present rates in their surrebuttal testimony. However, the Utilities believe it would be appropriate to reflect a reduction to the NOL deferred tax asset based on the tax impacts of the

[28] The People do not object to the 2013 NOL recorded in the test year.

> revenue increase that is granted in the final Order in this proceeding.

NS-PGL witness Stabile, at page 36 of NS-PGL Ex. 46.0, provides a limited explanation of the change:

> **Q. What is the status of an NOL in the Utilities' surrebuttal filing?**
> A. Because the Utilities have included the 2013 bonus depreciation estimates within the update for surrebuttal, they are now incurring losses in 2013. In addition, based upon the status of year end closing, the consolidated group is also in an NOL position.
>
> **Q. Have the Utilities included the deferred income tax effects of the NOL in it (sic) surrebuttal?**
> A. Yes. The Utilities have included stand-alone NOL amounts for *2012 and* 2013 in amounts at present rates information. See the surrebuttal testimony of Mr. Hengtgen for further details.

NS-PGL Ex. 46 at 36 (emphasis added). Mr. Stabile's Surrebuttal, as promised by Mr. Hengtgen, in fact do *not* provide the "further details" that he asserted would be forthcoming in the Stabile Surrebuttal testimony that would explain the basis for the NOL, the amounts of the adjustments or how they impact the rate base, or why they waited until the surrebuttal phase of the case to raise the *2012* NOL amounts.

While the Companies suggest that the need to reflect NOL amounts for both 2012 and 2013 is the federal government's extension of bonus depreciation, which occurred after the filing of their Rebuttal testimony, the fact is that the bonus depreciation (prior to the extension that was passed after January 1, 2013 by the U.S. Congress) was in existence throughout 2012. The Companies could have (and should have) estimated potential NOL effects as a result of the bonus depreciation in effect throughout 2012 as an issue either in its Direct or Rebuttal testimony filings. They did not, however.

Mr. Stabile specifically explained in his Rebuttal testimony, "If a utility has more tax deductions than taxable income in a given tax year, it has a tax NOL." NS-PGL Ex. 30.0 at 29. Mr. Stabile then further noted in his Rebuttal testimony that "no deferred tax asset exists as of the end of 2012 due to the consolidated groups (sic) income." *Id.* at 27. The Surrebuttal NOL adjustment associated with Congress's extension of the bonus depreciation goes well beyond the 2013 NOL amounts. The Companies' now show an NOL as of the end of 2012, which carries forward into the 2013 test year and affects the calculation of the Companies' revenue requirement to the detriment of ratepayers.

As a result of the Companies' delay in the presentation of this evidence, Staff and Intervenors were foreclosed from responding to this testimony, which significantly affects the Companies' proposed revenue requirements. According to NS-PGL Ex. 43.5P, inclusion of the 2012 NOL increases the PGL test year rate base by $38.597 million. According to NS-PGL Ex. 43.5N, inclusion of the 2012 NOL increases the NS average test year rate base by $2.123 million. If PGL/NS believed it was eligible to recognize an NOL in 2012, that fact could have been raised in an earlier evidentiary filing. Even putting aside the unexplained delay in raising the issue earlier in the case, the Companies have utterly failed to provide a witness to describe the source and cause of the NOL. The paucity of information regarding the proposed adjustment is particularly troubling given that the loss is somehow attributed to "the consolidated group" – presumably a reference to affiliated Integrys companies. NS-PGL Ex. 46.0 at 36.

Under the Commission's rules, utilities must present proposed ratemaking adjustments in the Direct phase of their case. The schedule established by the Administrative Law Judges in this case assumes that each phase of the evidentiary presentation responds to the prior testimony of other parties. Section 200.660 of the Commission's rules provides that a party "may be limited in the presentation of evidence in the proceeding or otherwise restricted in participation, to avoid undue delay and prejudice." 83 Ill. Admin. Code § 200.660.

The Companies' discussion of this new ratemaking proposal also violates Section

287.30 of the Commission's rules, which provides:

Section 287.30 Updates to Future Test Year Data

> a) During the suspension period, the assigned Administrative Law Judge may require or allow the utility to update its schedules and workpapers, if a utility has proposed a future test year, according to the schedule established in the proceeding when evidence has been introduced that a significant and material change affecting the revenue requirement as defined in subsection (c) of this Section has occurred. In establishing this schedule, the Administrative Law Judge shall consider the timing and scope of the updated filing. A utility shall not be allowed or required to submit more than one updated filing, or to submit an updated filing during the final 150 days of the resuspension period. When data are updated, the utility shall also provide updated information for any affected schedules and work papers originally submitted as a requirement of 83 Ill. Adm. Code 285.
>
> b) A determination to require or allow the submission of an update shall include, but not be limited to, the consideration of:

> 1) Whether the changes significantly and materially affect the revenue requirement;
> *2) Whether the changes could have been reflected in the initial tariff filing; and*
> *3) Whether the Illinois Commerce Commission staff and other participants will have an adequate opportunity to review the updated information.*
>
> c) *Examples of "significant and material" changes would include changes since the original filing of tariffs to factors including, but not limited to*:
> 1) Contractual obligations;
> *2) Revenue requirements*;
> 3) Additions or losses of customers served; and
> 4) Governmental requirements or levies, such as tax rates or environmental requirements.
>
> d) Whenever the utility updates projected data in its selected test year, it shall provide a reconciliation of original and updated data and identify and support the changes in its testimony and exhibits.
>
> e) Nothing in this Section shall be construed as a limitation on updates to the rate of return on rate base during the rebuttal phase of the rate proceeding.

83 Ill.Admin.Code Part 287.30. The 2012 NOL, which carries forward into the 2013 test year, could have been presented or raised as a possibility prior to the Utilities Surrebuttal testimony. The Utilities' decision to wait until Surrebuttal to propose this NOL adjustment means that Staff and Intervenors were not permitted to investigate the change through meaningful discovery, let alone comment upon the proposal in testimony.

It should be noted that it appears, based on Staff's Response to the People's Motion to Strike, that Staff witnesses have accepted the Companies' 2012 NOL rate base adjustment, despite the lack of information provided by the Companies explaining the loss and the delay in raising the issue. The Commission should not be satisfied, however, that the 2012 adjustment is necessary simply because of Staff's acquiescence. The People urge the Commission to reject the Companies' eleventh-hour attempt to increase rate base with an unexplained 2012 NOL, attributed to an Integrys affiliate occurrence.

CUB-City

CUB-City explain that for 2012, the Companies were allowed to take advantage of 50% bonus tax depreciation for certain new depreciable assets with a recovery period

of 20 years or less. *See* CUB-City Ex. 2.0 at 45. Therefore, rather than depreciating the asset equally over its life, a company (or utility) could depreciate 50% of the asset in its first year. For example, if a qualifying asset was worth $250,000 and was expected to last 20 years, per normal accounting rules, $12,500 should be charged per year to the company's expenses. Using bonus depreciation, the utility could deduct 50% of the purchase price of the asset, $125,000, rather than only $12,500, in 2012. If the company's net profit for 2012 was $100,000, then after the $125,000 deduction, the company would have a Net Operating Loss ("NOL") of $25,000.

CUB-City explain this 50% bonus depreciation was available in 2012 (Tr. at 736), and in the Companies' last rate case, 11-0280 cons., the Companies proposed an adjustment to recognize the existence of a resulting NOL. Staff Cross Exs. 12 and 13. CUB-City point out that, when asked in discovery about the 2012 NOL in this case, the Companies responded that their parent company, TEG, would be able to use the NOLs to obtain a tax benefit, and, thus, there was no rate base addition for 2012 NOLs reflected by the Companies. Staff Cross Exhibits 12 and 13, NS and PGL Schedule G-5. However, in the eleventh-hour, the Companies asserted -- for the first time – that they would use the 2012 NOL attributable to the bonus depreciation benefit. CUB-City maintain that the Companies' inconsistent statements on a 2012 NOL and on how the Companies' tax deductions, such as for depreciation, can be used on the consolidated income tax return (*see* Staff Cross Exhibits 12 and 13), should not result in any adjustment to the December 31, 2012 (beginning of the 2013 test year) opening balance of ADIT.

CUB-City note it is possible that 2013 bonus tax depreciation on plant additions for 2013, which is deductible for federal income tax purposes in 2013, could have resulted in an NOL for the Companies for 2013. However, 2013 bonus tax depreciation did not make any changes to the 2012 bonus tax depreciation or the corresponding deductions claimed on the federal income tax return for tax year 2012. Tr. at 736.

CUB-City state that an NOL, if caused by differences between book and federal income tax depreciation is required by federal tax regulations to be normalized, and increases rate base. The rate base increase occurs because NOL decreases ADIT, and ADIT decreases rate base. *See* Tr. at 82. CUB-City note that in October 2012, the Companies stated that PGL-NS would incur an NOL for 2012 on a stand-alone basis but Integrys Energy Group Inc. ("TEG") would be able to use the PGL and NS NOLs for 2012 to reduce current or prior tax obligations of the consolidated group. Staff Cross Exhibits 12 and 13, ("Similarly, for 2013, Peoples Gas would incur a NOL on a stand-alone basis, but TEG consolidated was assumed to absorb it. This assumption was disclosed on Schedule G-5."). Thus, say CUB-City, the Companies were aware at that time that the 2012 tax benefit would result in an NOL for that year. Staff Cross Ex. 12, Staff Cross Ex. 13. CUB-City point out that in all their case filings before surrebuttal, the Companies did not reflect any ADIT impact of 2012 NOLs in their rate base and stated that the Companies' 2012 deductions, including 2012 bonus tax depreciation, would be usable in the TEG consolidated return, so there was no ADIT impact on the utilities for 2012 NOLs.

CUB-City explain that Companies changed this position dramatically on surrebuttal. CUB-City aver that while they made the appropriate adjustment to reflect the availability 2013 bonus depreciation, the Companies also stepped backward and claimed the existence of stand-alone NOL amounts not just for 2013 but also for 2012. NS-PGL Ex. 46.0 at 36. CUB-City say that the Companies' update to reflect 2013 bonus depreciation, and the corresponding 2013 NOL, should have had no impact on a potential 2012 NOL. Indeed, note CUB-City, the Companies acknowledged the NOLs in Staff Cross Exhibits 12 and 13, where the Companies indicated that TEG would be using the NOLs. CUB-City argue that the December 31, 2012 balance for ADIT, which is the beginning ADIT balance for the 2013 test year, should reflect the utilities' full use of 2012 federal bonus tax depreciation and no rate base add-back for 2012 NOLs because the Companies' analysis, as stated in their direct and rebuttal filings and in response to specific discovery on this matter, indicated that their 2012 bonus tax depreciation could be fully utilized by Integrys on the 2012 consolidated return in which NS and PGL participate.

CUB-City respond to the Companies' argument that the American Taxpayer Relief Act of 2012 ("ATRA") impacted 2012 NOLs. CUB-City explain that the enactment of the ATRA affected only 2013 bonus depreciation, not 2012 bonus depreciation. The 2013 bonus tax depreciation did not make any changes to the 2012 bonus tax depreciation or the corresponding deductions claimed on the federal income tax return for tax year 2012. Tr. at 736.

2013 Bonus Depreciation and Net Operating Losses

CUB-City explain that on January 3, 2013, President Obama signed the ATRA, which extends the provision for 50% bonus federal tax depreciation through 2013. CUB-City Ex. 2.0 at 45. To be eligible for bonus depreciation, qualified property must be depreciable under the Modified Accelerated Cost Recovery System ("MACRS") and have a recovery period of 20 years or less. *Id*. at 45. These requirements encompass a wide variety of assets. *Id*. at 45. To qualify for the 50% bonus tax depreciation, the property must be new and placed in service before January 1, 2014 (January 1, 2015 for certain longer production period property and certain transportation property). *Id*. at 45-46.

Mr. Smith believes that most, if not all, of NS and PGL's 2013 plant additions will qualify for 2013 bonus federal tax depreciation. *Id*. at 46. Because of the timing of when the bonus federal tax depreciation was extended (the new law as signed on January 3, 2013, as noted above), the ADIT amounts in the Companies' direct and rebuttal filings did not reflect any impacts in the 2013 test year resulting from 2013 bonus tax depreciation. The result of being able to claim 2013 bonus federal tax depreciation has the impact of increasing the Companies' federal ADIT balances, subject to NOL-related limitations.

As shown in CUB-City Ex. 2.1, PGL's response to AG 20.01, PGL showed the impacts of 2013 bonus tax depreciation, which indicates the following two ADIT impacts:

1) ADIT credit balance increase of $47.619 million from 2013 bonus tax depreciation
2) ADIT rate base addition of $28.797 million for 2013 NOL attributable to 2013 bonus tax depreciation.

Similarly, for North Shore, CUB-City Ex. 2.1 page 25 of 41 shows these impacts from 2013 bonus tax depreciation:

1) ADIT credit balance increase of $3.250 million from 2013 bonus tax depreciation

2) ADIT rate base addition of $3.097 million for 2013 NOL attributable to 2013 bonus tax depreciation.

CUB-City note that These quantifications are labeled by NS-PGL as "preliminary estimates" but were at least conceptually consistent with the earlier responses of the Companies indicating that 2012 deductions would be fully usable and the significant portions of the 2013 deductions noted above would be usable and would result in increasing the December 31, 2013 (end of future test year) balances for ADIT by the net of the amounts listed from CUB-City 2.1 noted above.

CUB-City aver that the impact of 2013 bonus federal tax depreciation on 2013 test year ADIT balances should be fully reflected, subject to applicable NOL related limitations. The amounts presented by the Companies in CUB-City 2.1 (response to AG 20.01) appear to represent the most reasonable quantified impacts on ADIT from 2013 bonus tax depreciation in this record. CUB-City Ex. 2.0 at 46.

Consequently, CUB-City recommend that the December 31, 2012 (beginning of the 2013 test year) balance for ADIT reflect the full 2012 deductions for bonus federal tax depreciation in 2012. Additionally, the December 31, 2013 (end of the 2013 future test year) ADIT balance should reflect the net increases in ADIT from 2013 bonus federal tax depreciation subject to the NOL-related offsets shown in CUB-City Ex. 2.1 discussed above.

Commission Analysis and Conclusion

The Commission finds that the Utilities appropriately set forth its assumptions when it filed their direct case. The Utilities clearly indicated that based on forecasts at the time, while Peoples Gas or North Shore may individually be generating losses, the consolidated group was able to absorb such losses. The Commission also finds that through discovery and at its next opportunity to file testimony, the Utilities again updated the status of the NOLs, indicating again that it was forecasting that the consolidated group would be able to absorb the individual NOLs of Peoples Gas and North Shore. It would have been improper at either the direct stage or rebuttal stage to include the NOL

as CUB-City argues. Therefore, the Commission finds that the 2012 and 2013 NOLs are appropriate and should both be reflected in rate base.

The Commission further observes that two new facts occurred in January 2013: the Utilities closed their books making actual 2012 data available and (2) the American Taxpayer Relief Act of 2012 was enacted. Staff utilized some actual 2012 data when it updated its adjustment to North Shore's forecasted plant additions, further decreasing North Shore's rate base. All parties agree that the effects of the American Taxpayer Relief Act of 2012 was enacted, which extended bonus depreciation to 2013, be reflected in rate base. This also has the effect of reducing the Utilities' rate base. However, AG, and CUB-City argue against 2012 NOL, which is also new information only available in January 2013, which has a positive effect on rate base. In its reply brief, Staff agreed with the AG that the 2012 NOL should be removed from the revenue requirements. While Staff and the Companies agree on the effect, Staff does not agree that the 2012 NOL should be included. This methodology to reflect the impact of the revenue increase on the NOL and final revenue requirements is not contested between Staff and the Companies. The Commission must weigh all facts in evidence and it finds that it is proper to include both 2012 and 2013 NOLs in rate base.

Therefore, the derivative NOL adjustments will be reflected in the final operating statement and rate base schedules for the Companies based on the amount of revenue increase that is ultimately approved in this proceeding.

6. Accumulated Deferred Income Taxes –

a. Appropriate Methodology to Reflect Change in State Income Tax Rate

Utilities

The Utilities explain that differences between income and deductions recognized for financial statement purposes or "book" purposes as compared to tax return purposes are called "book to tax differences," which can be permanent or temporary. NS-PGL Ex. 30.0 Rev. at 4. One such temporary book-to-tax difference is depreciation; for financial statement purposes, straight-line depreciation is used and for tax purposes, accelerated depreciation is used. *Id.* at 4, 6. The Utilities also explain the interaction of Accumulated Deferred Income Taxes ("ADIT"), the book to tax differences for depreciation, and the impact of an income tax rate change. NS-PGL Init. Br. at 58-62. The Utilities also state that Docket No. 83-0309, Illinois Commerce Commission, On its Own Motion, Investigation into the appropriate accounting treatment of the deferred tax reserve resulting from changes in statutory income tax rate, dealt with this situation specifically, outside of a rate case, in an investigation in which all Illinois utilities participated. *Id.* A separate proceeding was initiated to provide a methodology of deferred income tax accounting such that uniform treatment would exist for the effects on ADIT resulting from income tax rate changes. *Id.* In its order in Docket No. 83-0309 ("83-0309 Order"), the Commission determined that all utilities use the Average Rate Assumption method, specifically finding that:

> the record herein establishes that the *utilization of the so-called weighted average method, requiring reversals or debits to the accumulated deferred tax reserve account by applying a weighted average historical tax rate to the excess of book depreciation for a given asset, appears most appropriate for ratemaking purposes for Illinois utilities* which utilize deferred tax accounting in that (a) it is consistent with generally accepted accounting principles and APB 11, (b) it is consistent with the Commission's Uniform System of Accounts, (c) it appears nonviolative of the IRS's prescription of normalization for utility ratemaking purposes, and (d) it is fair and equitable to both utility ratepayers and stockholders, and such uniform treatment for ratemaking purposes of such deferred tax accounts for Illinois utilities which utilize deferred tax accounting should be adopted in each utility's next rate filing, unless sooner prescribed by the Commission; provided, however, that such treatment should be presumptive only and can be rebutted for good cause shown;
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> ***
>
> IT IS THEREFORE ORDERED by the Illinois Commerce Commission that Illinois utilities subject to the Commission's jurisdiction over rates which utilize deferred tax accounting shall for ratemaking purposes account for reversals *resulting from changes in federal and Illinois corporate income tax rates* for income taxes deferred in prior years at the weighted average rates at which such deferred income taxes were originally recorded (i.e., by applying a weighted average historical tax rate to the excess of book depreciation for given assets); provided, however, that any accounting change required [*31] to conform with the weighted average method shall not be required until each utility's next rate filing, unless sooner prescribed by the Commission; and further provided, however, that such accounting treatment for ratemaking purposes shall be presumptive only and can be rebutted for good cause shown.

83-0309 Order, 1985 Ill. PUC Lexis 5 at *30-31. ARAM allows the return of excess (or recovery of deficient) ADIT over the remaining useful life of the assets, which gave rise to the excess (or deficient) deferred taxes. NS-PGL Init. Br. at 58-62. In the 83-0309 Order, the Commission notes that other jurisdictions at the time opted for a “quick payback” of excess depreciation but the Commission declined to adopt this methodology. *Id.* The Utilities state that ARAM has been used uniformly by Illinois utilities since 1985 for various tax rate changes, including the Tax Reform Act of 1986 (federal corporate rate reduced from 46% to 35%); the Omnibus Budget Reconciliation Act of 1993 (federal corporate tax rate increased from 34% to 35%); a 1989 Illinois state corporate combined tax increase from 6.4% to 7.18%; and a 2003 Illinois state corporate combined tax increase from 7.18% to 7.3%. NS-PGL Ex. 30.0 Rev. at 12. It

appears that in only two instances since the 83-0309 Order was entered did a utility use a method other than ARAM: ICC Docket No. 12-0321, ComEd's formula rate proceeding and Docket No. 12-0293, Ameren Illinois' formula rate proceeding. NS-PGL Ex. 46.0 at 19. In the ComEd proceeding, ComEd proposed a different methodology and in Ameren, the utility adopted a different methodology when raised by an intervenor. AG Cross Ex. 3.0; Docket No. 12-0321, Order at 32-33; Docket No. 12-0293, Order at 89-97. The records in those cases are absent any substantive debate on the merits of the methodology used versus ARAM, which all other Illinois utilities use. NS-PGL Ex. 30.0 Rev. at 13. The Utilities also cite *Central Illinois Public Service Co. v. Illinois Commerce Comm'n*, 243 Ill. App. 3d 421, 610 N.E.2d 1356 (1993), which upheld the use of ARAM.

The Utilities argue that the AG and CUB-City propose a method that is inconsistent with the existing regulations regarding normalization despite the concerns expressed in the 83-0309 Order that the methodology chosen to apply to both federal and state income tax changes be "nonviolative of the IRS's prescription of normalization for utility ratemaking purposes." Full normalization means that the amount of deferred income taxes recorded is the difference between (1) the actual tax liability (computed for example using accelerated depreciation) and (2) the tax liability if book expenses (such as straight-line depreciation) were used in the tax computation. NS-PGL Ex. 46.0 at 9. Utility normalization is prescribed in two places: the federal income tax rules on normalization and the FERC regulation on normalization. *Id.* The Utilities argue that the intervenors' methodology no longer reflects the difference between the actual tax liability and the tax liability based upon book expenses and thus no longer "nonviolative of the IRS's prescription of normalization for utility ratemaking purposes." The Utilities also note that the AG and CUB-City proposed methodology is inconsistent with Congressional intent allowing utilities to claim accelerated tax depreciation. NS-PGL Ex. 46.0 at 11. The Utilities argue that the AG and CUB-City proposed method is not a direct violation of normalization rules because at issue here is a change in state tax rate and not the federal tax rate. If a federal tax rate were at issue, the Utilities would likely need to seek a private letter ruling from the Internal Revenue Service ("IRS") before setting rates in accordance with the AG and CUB proposed method. *Id.* The Utilities state that CUB-City's reliance on Accounting Standards Codification ("ASC") 740, which is the GAAP method for computing deferred taxes is misplaced. GAAP has no reference to or definition for normalization; thus there is no "proper normalization accounting … as prescribed by GAAP" as CUB-City claim. The liability method described in ASC 740 is inconsistent with both the income tax and FERC regulations regarding normalization. However, GAAP acknowledges the situation where a prescribed regulatory method, such as ARAM, differs from the liability method as described in ASC 740, and under ASC 980, it allows a utility to record the difference between the two methods as a balance sheet adjustment. NS-PGL Ex. 46.0 at 17.

Further, the Utilities argue that the AG and CUB-City proposed partial flow through methodology distorts costs of service and does not balance and protect the interests of all stakeholders. This is contrary to the 83-0309 Order, which approves the ARAM methodology in part because "it is fair and equitable to both utility ratepayers and stockholders." 83-0309 Order, 1985 Ill. PUC Lexis 5 at *29-30. In fact, the proposed

methodology unfairly sacrifices future customers in order to provide a benefit to current customers. The Utilities state that by using ARAM, they provide the benefit of accelerated and bonus depreciation taken on an asset, which affects cost of service, over the life of the asset ensuring customers pay a normalized cost of the asset. However, the effect of the AG and CUB-City proposed methodology is that it lowers cost of service through a reduction for an estimated future tax benefit, in the initial year(s) an asset, flowing through a benefit to tax expense that is uncertain and that will actually be realized in a future period. For an asset, this benefit will not be repeated, and there is a resulting increase in the carrying cost of that asset in each subsequent year the asset is in service. NS-PGL Ex. 30.0 Rev. at 7. In other words, the tax benefit that under ARAM would be returned over the life of the asset that originated the book to tax difference is provided for immediately. The Utilities state that this is improper because future customers who will be paying for the same asset through depreciation are denied the benefit. The Utilities add that ARAM is fair to all customers as it normalizes the tax benefit or tax deficiency into rates over the assets' in-service lives – matching the depreciation expense which originally caused the book to tax difference. NS-PGL Ex. 30.0 Rev. at 8. Under ARAM, customers, current and future, all share in the burden of an income tax rate increase and enjoy the benefits of income tax rate decreases. *Id.* This is imperative as all these customers are funding the asset that created the book to tax difference and prevents any windfall to anyone group.

Finally, the Utilities note that in its 83-0309 Order, the Commission stressed the importance of establishing a uniform rule and stated that ARAM is presumptive and can be rebutted for good cause shown. 83-0309 Order, 1985 Ill. PUC Lexis 5 at *30-31. The AG and CUB-City propose a methodology that only two Illinois utilities, proposed under a formula rate statute, use. There is no other evidence indicating that any other Illinois utility has adopted a methodology other than ARAM. The AG and CUB-City proposal is inconsistent with the methodology provided under 83-0309 and they have not provided good cause as to why the Utilities must change their methodology. Further, a piecemeal process is not the proper way to ensure Illinois utilities are using a uniform methodology. Change in income tax rates should be treated consistently and not dealt with on a utility-by-utility basis, as this would lead to uneven results to cost of service and would vary as to when a rate case is filed. For example, Northern Illinois Gas Company ("Nicor"), as a result of its merger, agreed to not file a rate case for three years. If Nicor chooses a 2015 future test year, the test year would occur after the *temporary* state tax rate increase ends. Thus, Nicor customers would be precluded from ever receiving any of the "flow-through" benefits of the temporary schedule rates. This is just one example. Through initiating a separate docket (Docket No. 83-0309) in which all Illinois utilities were involved, uneven treatment of Illinois ratepayers is avoided.

The Utilities state that AG and CUB-City have provided no good reason why their proposed methodology should be adopted. Staff agrees.

Staff

Intervenor witness Brosch (AG Ex. 4.0 at 41; AG Ex. 4.1 and 4.2, Scheds. B-4) proposed an adjustment to reduce the ADIT provision to reflect the impact of scheduled decreases in the state income tax rate effective 2015 and again in 2025.

The Companies maintain their methodology of calculating ADIT using Average Rate Assumption Method ("ARAM") is consistent with the Commission's final order in Docket No. 83-0309; therefore, further adjustments are unnecessary. NS-PGL Ex. 46.0 at 2-19.

Staff did not take issue with the Companies' position, noting that based on Staff's understanding of the order in Docket No. 83-0309, the methodology appears reasonable. Staff Ex. 14.0 at 21-22.

AG

It is beyond dispute that Illinois State Income Tax Rates will not remain at the currently higher levels in all future years. State tax rates are scheduled to decline to 7.75% in 2015 and then return to the historical 7.3% in 2025. 35 ILCS 5/Art. 2;[29] see AG Ex. 1.0 at 34. Because most of the Companies' test year income tax expense is deferred, due to accelerated and bonus depreciation and other tax deductions, the future scheduled reduction in income tax rates will result in permanent income tax savings when today's deferred income taxes reverse and become payable. The Companies' calculation of deferred income tax expense for the test year, however, fails to acknowledge this future savings and will overcharge ratepayers. The Companies propose to hide behind a thirty year old Commission Order as the basis to employ a so-called "average rate assumption method" or "ARAM" as the basis to collect higher deferred income taxes today and then only gradually reflect the known and measurable savings in future years.

Boiling down this complex issue to its simplest essence, the Companies are taking income tax deductions today that allow the deferral of taxes that would otherwise be payable at the current, higher rate of 9.5%. AG Ex. 1.0 at 34. These deductions creates a timing difference where the Companies are booking deferred income taxes at the higher rate, but when the time comes to pay the taxes, the taxes will actually be paid at the lower tax rates scheduled to then be effective.

It must be noted from the outset that this issue was recently addressed by the Commission in the ComEd Formula Rate Docket, (ICC Docket No. 12-0321) and the Ameren Formula Rate Docket (12-0293). In ComEd, the Company proposed, and the Commission approved, a similar position as that proposed by the People in this docket. ComEd explained the change to revenue requirements in its testimony as follows:

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[29] Available at: http://www.ilga.gov/legislation/ilcs/ilcs4.asp?DocName=003500050HArt%2E+2&ActID=577&ChapterID=8&SeqStart=600000&SeqEnd=3100000

> Q. How did the increase in the Illinois income tax rate in 2011 impact the revenue requirement?
>
> A. The passage of Illinois Senate Bill 2505 on January 13, 2011 increased the previous corporate income tax rate of 7.3% to 9.50% for the years 2011 through 2014, with reductions to 7.75% in 2015 and 7.3% in 2025. This change impacts the revenue requirement in several ways.
>
> First, the statutory state income tax rate used to calculate the overall total income tax rate on Schedule FR C-4 has been revised to reflect the 9.5% statutory state income tax rate.
>
> Second, as a result of the change in the rate, previously recorded accumulated deferred income tax balances, i.e. balances as of December 31, 2010, were required to be remeasured to reflect the deferred tax balances calculated by applying the new tax rates noted above. The remeasurement of ADIT resulted in a required increase to jurisdictional ADIT as of January 1, 2011 of $13.1 million. Consistent with prior ICC guidance (ICC Docket No. 83-0309, addressing the manner in which deferred tax impacts resulting from tax rate changes should be addressed), this shortfall in ADIT is offset by a regulatory asset and is being amortized prospectively over the remaining life of the underlying assets by applying a weighted-average rate method for future reversals. Amortization of the remeasurement balance was a credit of $1.9 million in 2011.

AG Ex. 1.0 at 35-36, quoting ICC Docket 12-0321, ComEd Ex. 3.0 at 36-38.

Finally, in 2011, ComEd recognized a significant benefit due to the difference between the current income tax rate of 9.50% and the rate at which the related deferred tax expense is recorded. The deferred tax rate is lower because, as described above, the state income tax rate is scheduled to decline in 2015 and again in 2025, which means that some of the deferred taxes recorded in 2011 will reverse in later years when the state income tax rate is scheduled to be lower. This difference in current and deferred tax rates, combined with the fact that during 2011 ComEd had two notable and significant tax deductions (100% bonus depreciation and the expense related to the adoption of the T&D repairs safe harbor methodology) resulted in a 2011 tax benefit of $16,960,000 (jurisdictional), which is included in the tax adjustments shown on Schedule FR C-4.

The Commission accepted ComEd's position on this issue, noting that:

> ComEd submits that, consistent with Commission precedent, this shortfall in ADIT is offset by a regulatory asset and is being amortized prospectively over the remaining life of the underlying asset by applying a

> weighted average rate for future reversals. Amortization of the re-measurement balance resulted in a credit of $1.9 million in 2011.

ICC Docket 12-0321, Final Order (December 19, 2012) at 33.

Similarly, in the Ameren docket, the Commission adopted the position of ICC Staff and Interveners, including the AG, that the Company must adjust its deferred tax expense to reflect the future tax savings where it would be receiving benefit of lowered state income taxes. ICC Docket No. 12-0293, Final Order (December 12, 2012) at 97. In the ComEd docket, the Company recognized that it was realizing a significant 16.9 million benefit, given the difference between current income tax rate and the rate at which related deferred tax expense is recorded.[30]

Despite the Companies' arguments to the contrary, the accounting principles adopted in ComEd rate case and Ameren rate case apply in this docket. The Companies cite to a Commission's Order from Docket No. 83-0309 that they interpret as applicable in the instant docket. However, the 83-0309 Order does not apply directly to the facts surrounding the temporary increase in Illinois income tax rates in the 2013 test year. The Companies assert that the Average Rate Assumption Method (ARAM) accounting procedures were employed in their last set of rate cases (Docket Nos. 11-0280/0281 cons.). While this is factually accurate, a review of the Commission's Order from 11-0280/11-0281 reveals that the alternative approach followed by ComEd and Ameren, and approved by the Commission, was not at issue. *See, generally,* ICC Docket Nos. 11-0280/11-0281 Final Order. Furthermore, the Order in the Companies' prior rate case does not list income tax expense among the contested issues and the only ADIT dispute involved accounting for uncertain tax positions using a 50/50 sharing.

Moreover, the Companies proposed use of ARAM is incorrect in this situation because ARAM applies only to federal income taxes and not to the accounting for State income taxes. As Mr. Brosch explained in his testimony, Internal Revenue Code ("IRC") Section 168(e)[31] sets forth "Normalization Requirements" that must be satisfied for a taxpayer to continue to qualify for accelerated methods of tax depreciation and if such requirements are not satisfied, the taxpayer is limited to deduction of only straight-line depreciation on its federal income tax return. AG Ex. 1.0 at 39. These limitations have no applicability whatsoever to the Companies' rate case accounting for State income taxes. ARAM accounting was implemented in 1986 as part of the Tax Reform Act of 1986 (TRA 86) in consideration of federal income tax transition rules to protect utilities from any rapid flow-back by regulators of the then-excessive historically recorded federal ADIT balances, when Federal tax rates were reduced from 46 percent to 35 percent. This is not at issue in this docket. We are not dealing with Federal income taxes or with the flow-back of historically recorded ADIT balances. Instead, the instant issue involves provisions of State ADIT and the Companies' proposed use of ARAM should be disregarded by the Commission in favor of the methods employed for

[30] The adjustment reflecting a $16.9 million tax benefit is quantified at Docket 12-0293, ComEd Ex. 3.2, WP 9, at 2.
[31] Available at http://www.irs.gov/irb/2004-06_IRB/ar09.html.

deferred State income taxes in the aforementioned ComEd and Ameren rate proceedings.

As to the applicability of the Commission's order in 83-0309, that docket was an investigation into ratemaking and accounting for excess deferred federal income taxes that required *reversals* of reduced tax rates more than twenty years ago. As with the Companies' proposed use of ARAM, this is not at issue in this docket and the Commission should view its prior order in 83-0309 as inapposite in the instant docket.

In that docket, the Commission ordered

> "that utilities subject to the Commission's jurisdiction over rates which utilize deferred tax accounting shall for ratemaking purposes account for *reversals* resulting from changes in federal and Illinois corporate income tax rates for income taxes deferred in prior years at the weighted average rates at which such deferred income taxes were originally recorded…"

[emphasis added] ICC Docket 83-0309, Final Order (September 18,1985) at 30.[32]

As noted above, the issue in the current docket has been resolved by the Commission in the ComEd and Ameren formula rate proceedings. The current docket has nothing to do with excess deferred income taxes and has nothing to do with reversals of previously recorded ADIT balances. PGL and NS are able, and should be required, to practice the same liability method of accounting that is employed by ComEd and Ameren for deferred tax provisions based upon the state income tax rates that will be effective in future years when such provisions will reverse.[33]

Despite Companies' witness Mr. Stabile's argument to the contrary (NS-PGL Ex. 30.0 at 7), consistent utilization of the liability method of accounting for deferred income taxes (mandated under GAAP and approved by the Commission for use by ComEd and Ameren) does not cause "distortion." Mr. Stabile provided an illustration in NS-PGL Ex. 30.1 of this supposed distortion. However, the illustration is unreasonably focused upon only a single year of assumed capital additions, as though there is not a continuum of newly acquired or constructed utility assets in every tax year and every potential rate case test year. By focusing only upon a single tax year, Mr. Stabile is able to argue that "Customers in 2013 would pay approximately $2.1 million less for the use of those assets, as compared to customers in 2014." NS-PGL Ex. 30.0 at 7. The reality, however, is that "customers in 2014" would realize comparable deferred income tax

[32] See AG Exhibit 1.9 for a full copy of this decision, included as Attachment 2 to NS's response to AG 7.03.

[33] A liability method of accounting for Deferred Income Taxes is required under Accounting Standards Codification 840 ("ASC 840"). These requirements were previously referred to as Financial Accounting Standard 109 ("FAS 109") and require for financial reporting purposes that deferred taxes be provided in an amount sufficient to represent the estimated liability that will be paid when book/tax timing differences reverse in future period.

expense savings due to the Companies' expected acquisition and construction of new tax-deductible assets in 2014, and in every year thereafter.

In addition, the People's proposed adjustment does not "flow through" a non-repeating benefit that will subsequently increase the carrying cost of that asset, as Mr. Stabile argues. NS-PGL Ex. 30.0 at 7; NS-PGL Ex. 30.1. As noted by Mr. Brosch, the actual impact of using the liability method of accounting is to recognize *in each and every year* that income taxes being deferred on newly added assets should be quantified based upon the statutory tax rates that will be effective when such deferred taxes later become currently payable. As seen in the instant docket, with the scheduled reductions in the Illinois State Income Tax rates, deferral of taxes during period of higher tax rates that will actually be paid in distant future years, when tax rates are lower, represent very real and permanent income tax savings that should not be denied to ratepayers. The Companies' proposed use of ARAM accounting improperly complicates accounting and ratemaking for the temporarily higher State tax rates and charges customers a higher deferred income tax expense today than is expected to actually be paid in the future, when book/tax timing differences originating today will reverse.

Mr. Stabile's arguments on increased carrying costs are potentially misleading because they inherently assume that when customers should be indifferent to paying higher rates sooner versus later. The lower deferred income tax balances and incremental higher rate base under the AG/CUB method (and that approved in the ComEd and Ameren dockets) represent an accounting for the simple fact that ratepayers are not being forced to pay excessive deferred income tax expenses today when the flawed ARAM approach is rejected. The lower deferred tax balances and correspondingly larger future rate base amounts simply and consistently account for the time value of money during those years that the Companies are not receiving the larger tax deferral benefits Mr. Stabile would instead like to collect from customers under the ARAM method he supports.

Finally, the AG and CUB-City proposed adjustments are not "flow through" adjustments. Rather, they serve only to correct test year deferred tax expense calculations to account for differences between current and future statutory tax rates, using the GAAP-required liability method of tax normalization accounting, with no flowing through of the tax deferrals arising from annual additions to utility plant. There is no uncertainty created by using the AG/CUB proposed method of accounting. For ratemaking purposes, the deferred income tax expenses should be recorded at the income tax rates expected to be effective when book/tax timing differences reverse in future years under the liability method. If the legislature acts to again change income tax rates, a re-measurement of required deferred income taxes would again occur and adjustments to deferred income tax expense would result from the changed tax rates in future rate cases. The Companies should have no problem recovering income tax expenses that are recorded in future test years pursuant to applicable accounting rules, even if the result is a higher revenue requirement in rate cases.

CUB-City

CUB-City aver that issue here is the weighted average Illinois state income tax rate that should be used to record 2013 Deferred Income Tax Expense. CUB-City Ex. 2.0 at 42-43. This issue primarily affects Deferred State Income Tax Expense. In conjunction with the use of an average 2013 future test year for rate base in this case, CUB-City state the adjustment to reduce Deferred Income Tax Expense should also be coordinated with an adjustment to increase State ADIT by one-half the amount of expense reduction to reflect the related impact on State ADIT on average 2013 rate base. CUB-City explain that the typical journal entry to recognize the decrease in Deferred Income Tax Expense would involve reducing (crediting) Deferred Income Tax Expense and reducing (debiting) ADIT by the same amount to reflect the impact of the Illinois corporate income tax rates specified in the statute. CUB-City Ex. 2.0 at 31. Said another way, the same amounts should be used for the impacts on Deferred Income Tax Expense and the related end-of-period ADIT. *Id*. at 31. If a year-end rate base were to be used (and it should not), the adjustment to reduced Deferred Income Tax Expense would result in an equal amount of increase to ADIT. *Id.* at 31. CUB-City aver that in the context of the 2013 future test year, where an average test year rate base is being used, it would be appropriate to reflect an increase to rate base for the average test year for one-half of the reduction to Deferred Income Tax Expense. *Id*. at 31. CUB-City note that accounting for Deferred Income Tax Expense and ADIT typically entails a two-sided journal entry where one is debited and the other credited, or vice versa. *Id*. at 31. Reflecting the adjustment to ADIT in the average 2013 future test year rate base would appropriately recognize the related impact on ADIT that results from recording lower Deferred Income Tax Expense on average during the 2013 test year. *Id*. at 31-32.

CUB-City argue that the adjustment to reduce Deferred State Income Tax Expense must properly recognize the impact of the state income tax rates that are currently provided in the applicable Illinois income tax statute. CUB-City maintain that the Commission should apply standard utility normalization accounting for known changes in the Illinois State Income Tax Rate ("SIT"), just as it did in recent ComEd and Ameren formula rate cases. CUB-City Ex. 2.0 at 25, CUB-City Ex. 1.0 at 57-64. CUB-City note that Illinois *temporarily* increased its state corporate income tax rate, from 7.3% to 9.5%, effective January 1, 2011 and effective through 2014. CUB-City Ex. 1.0 at 55; *Id*. at 57. The 9.5% tax rate is composed of two components, a 7.0% income tax and a 2.5% personal property tax replacement income tax. *Id*. at 55-56, *citing* 35 ILCS 5/201(b)(10), 35 ILCS 5/201(d). In the years 2015-2024, the Illinois corporate income tax rate will be 7.75%, and beyond 2025 the rate will be 7.3%. CUB-City Ex. 1.0 at 57. Because the Illinois state corporate income tax rates specified in the statute decline in 2015 and 2025, a weighted average state income tax rate must be used to compute Deferred State Income Tax Expense, so that the lower tax rates used to determine deferred expense in later years are properly recognized in calculating the deferred liability used in this case.

CUB-City state that the Company's approach ignores the known future decline in state tax rates. CUB-City aver that the effect of the Companies' approach is to

overstate the Companies' Deferred State Income Tax Expense, increasing their revenue requirements. The future changes in state income tax rates that are specified in the current Illinois statute are required to be recognized under generally accepted accounting principles, for proper regulatory accounting and to be consistent with a proper application of the Commission's income tax normalization guidance from the Commission Order in Docket No. 83-0309. CUB-City Ex. 2.0 at 29-30. CUB-City aver that ignoring the known future tax rate changes, the Companies used a static state income tax rate of 9.5% to compute deferred state income tax expense for gas plant related timing differences. *Id*. at 65-66. This fails to reflect the known reductions in the Illinois state income tax rate, say CUB-City.

CUB-City further argue that the NS-PGL position on this issue is not only inconsistent with the Commission's treatment in the ComEd and Ameren cases cited above, in which the reduction to Deferred State Income Tax Expense was recognized, it also appears to be based on a biased mis-interpretation of the Commission's Order in Docket No. 83-0309, ("Order 83-0309") which addressed the need for consistent tax normalization accounting by Illinois utilities. In Order 83-0309, one of the objectives is to have consistency for income taxes among Illinois utilities. Tr. at 717. That Order stated: "such uniform treatment for ratemaking purposes of such deferred tax accounts for Illinois utilities which utilize deferred tax accounting should be adopted in each utility's next rate filing..." CUB-City Ex. 2.0 at 42-43. CUB-City state that the methodology Mr. Smith advocates is consistent with the Commission's decisions in Docket Nos. 12-0321 and 12-0293, where the Commission applied its own Order 83-0309 guidance to precisely the same tax situation in dispute this case. *Id*. at 42. If normalization accounting for the Illinois SIT rates specified in the state tax law that has been applied by ComEd and Ameren is not also applied by PGL and NS, uniform treatment would not be achieved. *Id*. at 43.

CUB-City aver that Mr. Stabile mischaracterizes the treatment proposed by CUB-City witness Smith and AG witness Brosch as "flow through" accounting. NS-PGL Ex. 30.0 at 6. CUB-City maintain that Mr. Smith's approach is not "flow through" accounting, which generally reflects passing through to ratepayers the tax savings associated with a tax deduction in the *current* period, rather than establishing a Deferred Income Tax Expense to normalize that deduction. CUB-City Ex. 2.0 at 27-28. CUB-City note that neither ComEd nor Ameren applied "flow through" accounting for their recognition of the lower amount of Deferred State Income Tax Expense to recognize the known Illinois state corporate income tax rates, and that is not what Mr. Smith proposes here. Mr. Smith, like ComEd and Ameren, used normalization accounting for Illinois state income taxes. *Id*. at 29-30.

While Mr. Stabile claims that the average rate assumption method ("ARAM") is the appropriate accounting treatment of state income taxes, and he references the Order 83-0309 as support, CUB-City maintain that his presentation is conceptually incorrect. Order 83-0309 did not address future changes in the Illinois state income tax rate. CUB-City Ex. 1.0 at 64. Instead, CUB-City state that Order 83-0309 concerned

past changes in the federal income tax rates that resulted from the Reagan corporate income tax rate cuts and did not address known future rate changes. *Id*. at 64.

CUB-City aver that the Companies misinterpret and misapply the guidance provided in the Order 83-0309, by claiming that it calls for the ARAM method. NS-PGL Ex. 30.0 at 4. That guidance required that:

> Illinois utilities subject to the Commission's jurisdiction over rates which utilize deferred tax accounting shall for ratemaking purposes account for *reversals resulting from changes in federal and Illinois corporate income tax rates deferred in prior years at the weighted average rates at which such deferred taxes were originally recorded*.

ICC Docket 83-0309 Final Order (cited by NS-PGL Ex.30.0 at 11-12) (emphasis added). Mr. Smith's analysis complies with this stated policy. In years following 2013, when the Deferred Income Taxes initially recorded in 2013 are being reversed, CUB-City say the same weighted average state income tax rates that were used for the initial recognition should continue to apply when accounting for those reversals. CUB-City Ex. 2.0 at 42.

CUB-City aver that Companies are subject to the same GAAP, Internal Revenue Code, APB Accounting Rules, and Commission guidance for deferred income taxes as ComEd and Ameren. The Commission's determination was articulated almost 30 years ago in the Order 83-0309. Tr. at 774. CUB-City argue that ComEd and Ameren have applied that guidance appropriately, whereas NS/PGL have not. As Mr. Fruehe described in the ComEd formula rate docket (Docket No. 12-0321), the application of ARAM from Order 83-0309 did not negate the need for ComEd's adjustment to reduce Deferred State Income Tax expense to properly recognize known state income tax rate changes that are currently prescribed in the applicable Illinois statutes. CUB-City Ex. 2.0 at 28.

CUB-City aver that the methodology used by Mr. Smith applies standard utility normalization accounting for known, statutorily specified Illinois state income tax rates to compute Deferred Income Tax Expense. CUB-City Ex. 2.0 at 27. GAAP and regulatory accounting require recognition of the lower Deferred Income Tax Expense. *Id*. at 28. CUB-City oppose the Companies' proposal as it is not consistent with GAAP. *Id*. at 34. The Companies rely in part on Accounting Principles Board Opinion No. 11 ("APB 11"), cited in Order 83-0309, as the basis for their position. NS-PGL Ex. 30.0 at 11. However, CUB-City note that Mr. Stabile himself agreed that opinion was issued in the 1960s, and it is no longer part of GAAP. Tr. at 718-719. CUB-City explain that the opinion on which the Companies rely was superseded and replaced by Financial Accounting Standards Board ("FASB") Statement No. 109 and Accounting Standards Codification ("ASC") Section 740. *Id*. at 719, CUB-City Ex. 2.0 at 41. ASC 740 represents the current GAAP codification on accounting for income taxes. Tr. at 719, CUB-City Ex. 2.0 at 41. Under ASC 740, deferred income tax impacts of temporary book-tax basis differences are to be accounted for at the statutory income tax rates. *Id*.

Therefore, in accordance with GAAP, the weighted average statutory state income tax rates should be applied to compute Deferred Income Tax Expense. *Id*. at 42.

CUB-City contend that Mr. Smith's approach is the only reasonable interpretation of the pertinent accounting prescriptions (Order 83-0309, GAAP and regulatory accounting) and past Commission decisions relating to the accounting for known statutory changes in state income tax rates, and it should be adopted by the Commission.

Commission Analysis and Conclusion

The Utilities argue that they are complying with a directive that all Illinois utilities have followed since 1985 when the 83-0309 Order was entered. This conclusion from the order was applicable to income tax rate changes past and future and was applicable to both federal and state rate changes, no matter their form. Staff does not take exception to the method chosen by the Utilities. However, there is a provision in the 83-0309 Order indicating that the use of ARAM can be rebutted for good cause, based on the record in this matter, the Commission accepts the position of the AG and CUB-City on this issue. Because the Illinois state corporate income tax rates specified in the statute a decline in 2015 and 2025, a weighted average state income tax rate must be used to compute Deferred State Income Tax Expense, so that the lower tax rates used to determine deferred expense in later years are properly recognized in calculating the deferred liability used in this case. The lower deferred income tax balances and incremental higher rate base under the AG/CUB method (and that approved in the ComEd and Ameren dockets) represent an accounting for the simple fact that ratepayers are not being forced to pay excessive deferred income tax expenses today when the flawed ARAM approach is rejected. The lower deferred tax balances and correspondingly larger future rate base amounts simply and consistently account for the time value of money during those years that the Companies are not receiving the larger tax deferral benefits that would be collected from customers under the ARAM method. If the legislature acts to again change income tax rates, a re-measurement of required deferred income taxes would again occur and adjustments to deferred income tax expense would result from the changed tax rates in future rate cases. The Companies should have no problem recovering income tax expenses that are recorded in future test years pursuant to applicable accounting rules, even if the result is a higher revenue requirement in rate cases.

b. Repairs Deduction Related to AMRP Projects

Utilities

In its 2009 tax return, Peoples Gas elected to change its tax method of accounting for the determination of whether an expenditure is a capital asset or repairs and maintenance ("repairs deduction"). PGL Ex. 10.0 at 8-9. In its direct filing, the Utilities reflected the benefit of this election despite continued audit risk. In particular, the Utilities note that based on developments at the time of direct filing, including the

issuance of Revenue Procedure 2011-43 and proposed Treasury Regulations, it could make some reasonable assumptions regarding the repairs deduction:

> (1) The Industry Issue Resolution ("IIR") process related to gas distribution property would result in an *electable* safe harbor similar to the electric transmission and distribution ("T&D") safe harbor;
>
> (2) The Utilities will be satisfied with the tax benefit that the safe harbor method provides and will elect the safe harbor method; and
>
> (3) The election to use the safe harbor method will include a similar transition provision in that it will come in the form of a new method change adopted in a future tax year.

Id. At the time of its direct filing, based on the information available, Peoples Gas believed that only 40% of AMRP costs would qualify for the repairs deduction. NS-PGL Ex. 46.0 at 26. Peoples Gas' position was supported in part by participants engaged in the ongoing Industry Issue Resolution ("IIR") program, which indicated that the guidance for gas utilities would be similar to Revenue Procedure 2011-43 and that such guidance would be issued in time for filing Peoples Gas' 2011 tax return. *Id.* However, by the time Peoples Gas filed rebuttal testimony, it believed and it continues to believe, that the IRS would not allow a repair deduction for any portion of AMRP projects. This conclusion was based on a number of factors. First, Revenue Procedure 2011-43 was a procedure for *electric* transmission and distribution ("T&D") companies that included safe harbor guidance in determining whether an expenditure for electric T&D constituted a repair for tax purposes. It cannot be relied upon by a gas utility to meet the tax return positions set forth in the Statement on Standards for Tax Services No. 1. NS-PGL Ex. 46.0 at 27-29. What is useful information is the IRS' application of Revenue Procedure 2011-43 to electric T&D. This procedure provides two exceptions to the safe harbor guidance that if contained in the future gas industry guidance, Peoples Gas believed that no portion of AMRP costs would qualify as repairs based on the application of these exceptions to electric T&D companies. NS-PGL Ex. 30.0 Rev. at 18-20. This conclusion is based on the experience of electric T&D companies in applying Revenue Procedure 2011-43 that came to Peoples Gas' attention after filing its direct case. *Id.*

Further, the nature of AMRP, following the reversal of Rider ICR by the Appellate Court and through the testimony submitted in this proceeding, is clearly becoming part of a plan of rehabilitation, modernization, or improvement, which is an exception to the safe harbor rule set forth in Revenue Procedure 2011-43. Additionally, the IRS has already indicated that additional guidance was needed to make Revenue Procedure 2011-43 work as intended (as differences in interpretation of key provisions exist) and that guidance would not be received until sometime in 2013 at the earliest. Furthermore, the IRS has indicated that there was a delay in the release of the guidance for gas T&D industry, which also would not be expected until sometime in 2013. Finally, Peoples Gas has indicated that it has not taken the repairs deduction related to AMRP projects on its 2011 return and there is no basis for a repair deduction related to AMRP projects in its 2012 return which is due to be filed in September 2013.

NS-PGL Ex. 46.0 at 27; Tr. at 757. Peoples Gas' cautious behavior based on these facts and circumstances is not imprudent. Peoples Gas' shareholder is not benefitting by not expending the repairs deduction to AMRP projects.

Peoples Gas states that the AG claims that Peoples Gas should claim a repairs expense deduction for AMRP projects even though it has not claimed a deduction on its 2011 return or will not claim a deduction on its 2012 return for AMRP projects. Peoples Gas explains that based on a lack of guidance to the gas industry regarding the repairs election, the experience of the electric industry with similar guidance, and other developments in the industry and in this proceeding, Peoples Gas determined that it will no longer take a repairs deduction regarding AMRP projects. The AG provides little to no evidence to rebut this conclusion. Also, Peoples Gas' position is based upon applying representations it made to the IRS on Form 3115 when making the election and other applicable law to the 2011 AMRP projects, Peoples Gas could not meet the reporting standard as set forth in the Statement of Standards for Tax Services No. 1. As such, Peoples Gas did not claim the deduction as it relates to AMRP projects on its 2011 return. Further the AG's proposal is similar to the situation where AG witness Mr. Effron attempted to impute the repairs election on ComEd in Docket No. 10-0467. The Commission denied it in that docket and it should do so here. Finally, he AG's reliance on The Narragansett Electric Company, d/b/a National Grid Gas ("National Grid") case is without merit. National Grid's Infrastructure, Safety, and Reliability program is not substantially similar to Peoples Gas' AMRP.

Staff

In its direct filing, Peoples Gas assumed approximately 40% of AMRP costs would qualify for immediate tax deduction as repairs and maintenance expenses. Based on further developments in the treatment of electric transmission and distribution ("T & D") costs by the IRS, the Company changed its tax position regarding AMRP costs, asserting the tax deductions in the Companies' direct filing are not supportable given the guidance issued for electric T & D companies. Without a reasonable expectation that the IRS will allow these deductions, the Company does not intend to take the position on an originally filed tax return or amended claim. Peoples Gas asserts that GAAP would not permit recognition of the tax benefits and resulting deferred taxes. Therefore, in rebuttal testimony, Peoples Gas decreased its deferred tax liability by $47.2 million as of December 31, 2013 reflecting AMRP costs being capitalized instead of expensed. NS-PGL Ex. 30.0 at 17 – 20.

According to Staff, Intervenor witness Effron concluded Peoples Gas had not substantiated the basis for its change in tax accounting method for AMRP costs and proposed to restore the Company's deferred tax benefit related to expense treatment of such costs. Mr. Effron's adjustment assumes an average rate base methodology that would increase the ADIT liability and reduce average rate base by $32.347 million. AG Ex. 5.0 at 4-9; AG Ex. 5.1. Staff does not support this position.

Neither Staff nor CUB-City witness Smith contested the Companies' position.

AG

As the Commission recently stated, "Generally, ADIT quantifies the income taxes that are deferred when the tax law provides for deductions with respect to an item, in a year other than the year in which the item is treated as an expense for financial reporting purposes. For regulated entities, ADIT is treated as a non-cost source of capital that reduces rate base." ICC Docket 11-0721, Order at 56, citing *Ameren Illinois Co. v. Ill. Commerce Comm'n*, 2012 IL APP (4th) 100962 at 5, 2012 Ill.App.3d LEXIS 175 (4th Dist. 2012). As the Commission has noted in several previous orders, until the Companies' actually pay their deferred tax liabilities to the relevant taxing authorities, they represent non-investor supplied funds available to the Companies. In this docket, the Companies are not properly recognizing the appropriate balances of ADIT in their determination of the test year rate bases. The Commission should reject the Companies' deviation from the standard treatment of ADITs and reduce rate base accordingly to reflect non-investor capital available as a result of the Companies' repairs deductions and elimination of the unexplained and undocumented 2012 net operating loss.

The Companies' rebuttal testimony unveiled an unexpected reversal of course that will cost ratepayers dearly: the Companies no longer believe that AMRP costs qualify under safe harbor guidance as deductible tax repairs that would reduce rate base. NS-PGL Ex. 46.0 at 30. The net effect of this reversal is a decrease in ADIT of over $47 million as of the end of 2013, resulting in an over $32 million increase in its average test year rate base[34] – an increase that falls squarely on the shoulders of ratepayers. Although PGL claims that plant costs related to AMRP could no longer be treated as tax repairs, PGL has failed to justify its reversal on this issue.

In PGL's direct case, the Company assumed that its AMRP should be treated as any other distribution facility project for the purposes of repairs deductions. NS-PGL Ex. 30.0 at 17. In rebuttal testimony, however, Company witness Stabile testified that the Company had reviewed the guidance provided in IRS Revenue Procedure 2011-43, but in the absence of a bright line rule, the Company felt it was no longer reasonable to classify AMRP expenses as repairs for tax purposes. *Id*. at 17-18.

PGL's premises for changing their treatment of AMRP costs appear to be quite thin. At the time of their direct testimony, some of the 2012 and 2013 AMRP plant costs were treated as tax repairs; at the time of rebuttal testimony, it was assumed none of those costs would qualify as tax repairs. Peoples Gas has not established that the assumptions in its rebuttal testimony are more valid than the treatment adopted in its direct testimony. Unless Peoples Gas can better substantiate why the tax treatment of the AMRP costs in its direct testimony was inappropriate, the determination of the test year balance of ADIT and rate base should continue to reflect that treatment.

The Company notes that its original position was no longer reasonable because of a change to its interpretation of IRS Revenue Procedure 2011-43. AG Ex. 5.2 at 1-3.

[34] AG Ex. 5.0 at 4.

Procedure 2011-43 outlines which plant repairs would qualify as repairs for tax income deferral for electric utilities. In particular, PGL cited to the issuance of IRS Revenue Procedure 2012-39, which delayed the implementation of Procedure 2011-43 by one year. However, AG witness Effron's interpretation of Procedure 2012-39 is that the new Procedure only delayed implementation of certain *limitations* in 2011-43, it did not impose new restrictive guidelines as to what would qualify as a tax repair. AG Ex. 5.0 at 5 (emphasis added).

In its response to AG Data Request 15.09, PGL also noted that the lack of IRS guidelines specifically applicable to gas utilities. AG Ex. 5.2 at 3-4. Other than this thin reason, PGL has not explained why Procedure 2012-39 would cause it to believe expenditures that it previously believed would qualify as tax repairs no longer qualify. Also in the response to AG Data Request 15.09, PGL noted the "evolution of the public record in the instant case from July 31, 2012 to the present" related to the AMRP as a changed circumstance. *Id.* at 4. Aside from this obtuse description, the Company cites to nothing in the public record of the instant docket that somehow changed the basic nature of the AMRP and it cites to no specific changes to AMRP that now cause AMRP expenditures to not qualify as tax repairs, whereas they had previously qualified. Finally, PGL responded that the IRS has not released specific guidance providing the gas transmission and distribution industry ("Gas T&D") with a safe harbor method of accounting for tax repairs. *Id*. at 4. While PGL may have anticipated that guidance would have been issued by now, the fact that the IRS has not released such guidance does not amount to a change in facts or circumstances and it certainly does not amount to a reason to saddle ratepayers with providing the Company with a cost-free loan via increased rates. The People's proposed adjustment is fair and reasonable and is not overcome by the Company's protestations to the contrary.

Certain of PGL's claims are simply implausible. For example, PGL asserts that did not start looking at how the AMRP would be treated for tax purposes until October 2012.[35] Given the size of the AMRP program and the length of time that the program has been either under consideration or in place, it is difficult to understand how IBS Tax would not start looking at how AMRP would be viewed until October 2012. This is simply not a plausible excuse for the Company's change in the treatment of AMRP costs and should be rejected by the Commission.

PGL also now claims that AMRP could be caught under two exceptions: per se capital expenditures (which cannot be treated as tax repairs under any circumstances) and the aggregation rule (aggregation of expenditures to determine whether they exceed 10% of a unit of property – which would disqualify them from tax repair deductions). AG Ex. 5.2 at 6. However, these exceptions to the safe harbor are not new or novel. They existed in the Procedure that was in place before PGL filed its direct case.

[35] "IBS Tax reviewed the Utilities' testimony related to estimates of capital expenditures related to gas main replacements. Subsequent to that review, multiple data requests by Staff and intervenors were made seeking specifics related to the Utilities' estimated AMRP expenditures. Based on this analysis, IBS Tax started looking at how AMRP would be viewed." AG Ex. 5.2 at 7.

AG witness Mr. Effron also noted that PGL's position is not the most common or preferred position in the utility industry – noting that more than 60% of utilities have filed method changes for tax repairs. AG Ex. 5.0 at 8. In Mr. Effron's experience in a rate case in another state, Rhode Island's gas utility, Narragansett Electric Company, replaced a series of gas mains on an accelerated basis and concluded that almost half of its repairs would qualify as tax repairs.

Given the paper-thin justifications provided by the Company to explain its position, the Commission should adopt the AG position.

Commission Analysis and Conclusion

The evidence demonstrates that even though the Utilities have elected the repairs deduction, there is still substantial uncertainty related to the repairs deduction. Peoples Gas has not claimed the repairs deduction for AMRP-related projects on its 2011 tax return and does not currently expect to claim this deduction on its 2012 tax return to be filed in September 2013. The IRS has not even issued guidance for gas utilities and there appears substantial doubt on how even the guidance issued to electric utilities is applied. Therefore, we cannot conclude that Peoples Gas' cautious behavior with the IRS, without more, is an act of imprudence.

c. Bonus Depreciation

Utilities

In January 2013, the American Taxpayer Relief Act of 2012 was enacted and it extended the availability of 50% bonus depreciation into 2013. The Utilities expect to elect to take bonus depreciation in 2013. NS-PGL Ex. 46.0 at 34. There appears to be no dispute that the appropriate adjustments to ADIT for year end rate bases are $47.2 million for Peoples Gas and $3.2 million for North Shore (for an average rate base, the adjustments are $23.618 million for Peoples Gas and $1.625 million for North Shore).

However, The Utilities state that if the Commission determines that the 2012 NOL should not be included in computing rate base as discussed in Section IV.C.5 of this Order, then bonus depreciation should not be included in determining ADIT. Failure to include the 2012 NOL in rate base would likely lead to a violation of the normalization rules. Tr. at 777. A consequence of such a violation is the loss of accelerated depreciation, which includes bonus depreciation. NS-PGL Ex. 30.0 Rev. at 33. As such, the Utilities state that the inclusion of bonus depreciation at the very least would be improper.

AG

The People do not object to the Companies' proposed $47,235,373 (PGL) and $3,250,333 (NS) adjustments to ADIT and rate base as a result of claiming bonus

depreciation for 2012 and 2013 as outlined in Mr. Stabile's surrebuttal testimony. NS-PGL Ex. 46.0 at 34-36.

Commission Analysis and Conclusion

The Commission finds that bonus depreciation resulting from the American Taxpayer Relief Act of 2012 as extended into 2013 is appropriate for recovery in the revenue requirement. The appropriate amount for recovery, considering the decision on average versus year end rate base, is reflected in the Average Rate Base adjustment. Having found that the 2012 and 2013 NOLs should be included in rate base, we do not have to reach the normalization issue.

d. Derivative Adjustments from Contested Adjustments

Apart from the items discussed in Section IV.C.6.a, b, and c, above, this is an uncontested issue that depends on the outcome of other issues discussed elsewhere in this Order. The Commission's conclusions are reflected in the Appendices.

C. Accumulated Depreciation (Uncontested Except for Derivative Adjustments from Contested Adjustments)

This is an uncontested issue that depends on the outcome of other issues discussed elsewhere in this Order. The Commission's conclusions are reflected in the Appendices.

V. OPERATING EXPENSES

A. Overview

North Shore proposes base rate operating expenses in the amount of $72,424,000, reflecting the Staff and intervenor adjustments that it adopted or accepted in whole or in part in order to narrow the issues and certain updates. NS-PGL Ex. 42.1P, line 33, col. [H].

Peoples Gas proposes base rate operating expenses in the amount of $527,779,000, reflecting the Staff and intervenor adjustments that it adopted or accepted in whole or in part in order to narrow the issues and certain updates. NS-PGL Ex. 42.1P, line 33, col. [H].

The Utilities presented evidence concerning their operating expenses, including the testimony of six witnesses on the following topics: (1) the test year, the overall revenue requirement, operating expenses, operating income, rate case expenses, and the Gross Revenue Conversion Factor, and underlying calculations and support of numerous components of operating expenses; (2) the test year forecast and associated "Part 285" Schedules, significant variances year over year from prior years to the test year in amounts recorded in operating expense Accounts, bad debt expense, depreciation and amortization expense, taxes other than income taxes expense, and intercompany costs; (3) employee headcounts, expenses associated with the Chicago Department of Transportation regulation changes and the Utilities' cross bore program;

(4) incentive compensation program expenses and non-union base wage increases; (5) income taxes and invested capital taxes; and (6) employee benefits operating expenses, including pensions, OPEB, group insurance, and Integrys Business Support, LLC ("IBS") billed benefits. NS-PGL Init. Br. at 72-73.

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

1. Administrative & General

a. Interest Expense on Budget Payment Plan

In surrebuttal testimony, the Utilities accepted Staff's proposed adjustments of interest expense on budget payment plan based on the December 19, 2012, Commission ruling setting the 2013 rate of interest to be paid at 0%. The Utilities clarified that the adjusted amounts should be taken from the O&M ratemaking adjustments included in the Utilities' revenue requirements that were filed in direct testimony as Schedules C-2.9 and C-2.10. Staff Ex. 12.0 Rev. at 24-25; NS-PGL Ex. 42.0 Rev. at 4. The Commission approves Staff's recommended adjustment, as clarified by the Utilities, of interest expense on Peoples Gas' and North Shore's budget payment plan.

b. Interest Expense on Customer Deposits

In surrebuttal testimony, the Utilities accepted Staff's proposed adjustments of interest expense on customer deposit based on the December 19, 2012 Commission ruling setting the 2013 rate of interest to be paid at 0%. The Utilities clarified that the adjusted amounts should be taken from the O&M ratemaking adjustments included in the Utilities' revenue requirements that were filed in direct testimony as Schedules C-2.9 and C-2.10. Staff Ex. 12.0 Rev. at 24; NS-PGL Ex. 42.0 Rev. at 4. The Commission approves Staff's recommended adjustment, as clarified by the Utilities, of interest expense on Peoples Gas' and North Shore's customer deposits.

c. Lobbying Expenses

In rebuttal testimony, the Utilities accepted Staff's proposed adjustments disallowing expenses for lobbying and related activities. Staff Ex. 3.0 at 16; NS-PGL Ex. 26.0 at 4-5. The Commission approves Staff's adjustments.

d. Social and Service Club Dues

In rebuttal testimony, the Utilities accepted Staff's proposed adjustment to social and service club membership dues. Staff Ex. 3.0 at 15; NS-PGL Ex. 26.0 at 4-5. The Commission approves Staff's adjustments.

e. Executive Perquisites

In rebuttal testimony, the Utilities accepted Staff's proposed adjustment to executive perquisites. Staff Ex. 3.0 at 17-18; NS-PGL Ex. 26.0 at 4-5. The Commission approves Staff's adjustments.

f. Consulting Expense – SIG Consulting

In rebuttal testimony, the Utilities accepted Staff's proposed adjustment to consulting expenses for Strategic International Group, LLC. Staff Ex. 3.0 at 20-21; NS-PGL Ex. 26.0 at 4-5. The Commission approves Staff's adjustments.

g. Employee/Retiree Perquisites – Awassa Lodge

In rebuttal testimony, the Utilities accepted Staff's proposed adjustment to expenses related to Awassa Lodge. Staff Ex. 4.0 at 24; NS-PGL Ex. 26.0 at 4-5. The Commission approves Staff's adjustments.

h. Update to Pension and Benefits

In rebuttal testimony, the Utilities updated pension and OPEB expenses to reflect the most recent actuarial report, which increased these expenses by $979,000 for North Shore and $7,201,000 for Peoples Gas. NS-PGL Ex. 26.0 at 14. No parties contested the updated amounts. The Commission approves the Utilities' pension and OPEB expenses.

i. Update to IBS Return on Investment

The Utilities and the AG agree that the rate of returns for the IBS return on investment included in the Utilities' revenue requirements should reflect the final approved rates of return. AG Ex. 1.0 at 50-51; NS-PGL Ex. 26.0 at 4-5. No other party disagrees. The Commission approves this methodology.

j. Costs to Achieve Amortization

In rebuttal testimony, the Utilities updated the amortization of costs incurred to achieve savings. NS-PGL Ex. 26.0 at 13. This was not contested. The Commission approves the Utilities' adjustment to the amortization of these costs.

2. Uncollectible Account Expense Included in Base Rates

In rebuttal testimony, the Utilities accepted Staff's proposed adjustment to the base rate uncollectible accounts expense. Staff Ex. 2.0 at 27; NS-PGL Ex. 26.0 at 4-6. The Commission approves Staff's adjustment.

3. Depreciation Expense

a. WAM System

In surrebuttal testimony, the Utilities updated adjustments for IBS depreciation expense on the Work Asset Management ("WAM") system. NS-PGL Ex. 42.0 Rev. at 11; NS-PGL Ex. 41.0 Corr. at 5. The adjustments were not contested, but the amount

of the adjustment is potentially contested elsewhere in this Order. The Commission approves the Utilities' adjustment and notes that the amount of the adjustment is discussed in Section V.C.7.a of this Order.

b. CNG Plant

In surrebuttal testimony, the Utilities accepted Staff's proposed adjustment to CNG Plant for Peoples Gas to reflect the reclassifications of the depreciation expense and income taxes from utility plant in service to a non-utility plant. NS-PGL Ex. 42.0 Rev. at 13; NS-PGL Ex. 43.0 at 4. The Commission approves Staff's adjustment.

4. Income Tax Expense – Changes in Interest Expense On Debt Financing

In rebuttal testimony, the Utilities accepted Staff and intervenor adjustments to income taxes that relate to changes in interest expense on debt financing as well as to changes to the forecasted interest rates on short-term and long-term debt. NS-PGL Ex. 26.0 at 15; NS-PGL Ex. 23.0 at 3. The Commission approves Staff and intervenor's adjustments to these amounts.

5. Revenues

a. Sales and Revenue Adjustment by Service Classification

AG witness Mr. Effron proposed to eliminate the Utilities' forecasted sales decreases and to base their forecasted sales for the 2013 test year at their actual 2011 weather normalized sales. This adjustment would increase Peoples Gas' sales to Service Classification ("S.C.") No. 1 – Small Residential Service by 17,361,000 therms and S.C. No. 2 – General Service by 19,481,000 therms and North Shore's sales to S.C. No. 2 – General Service by 1,963,000 therms. AG Ex. 2.0 at 18-20; AG Ex. 2.1, Sched. DJE-2N; AG Ex. 2.1, Sched. DJE-2P. The Utilities did not contest these adjustments. NS-PGL Ex. 40.0 at 3; NS-PGL Exs. 40.1 and 40.2.

The Utilities provided Staff with blocked test year sales for the different meter classes. NS-PGL Exs. 40.3 – 40.5. In rebuttal testimony, AG witness Mr. Rubin provided different blocking based on a different sales adjustment for Peoples Gas S.C. No. 1, but no blocking to reflect the AG's proposed sales adjustments for Peoples Gas S.C. No. 2 or North Shore S.C. No. 2. NS-PGL Ex. 40.0 at 3-4. The AG does not contest the Utilities' blocking for Mr. Effron's sales adjustment.

The Commission adopts the uncontested adjustment proposed by the AG to eliminate the Utilities' forecasted sales decreases and to base their forecasted sales for the 2013 test year at their actual 2011 weather normalized sales. Further, the Commission adopts the blocking provided by the Utilities for test year sales for the different meter classes as shown in NS-PGL Exs. 40.3 – 40.5.

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

1. Incentive Compensation (Falls in Multiple Categories of O&M)

Utilities

The Utilities explain that they have three different incentive compensation plans: (i) an Executive Incentive Compensation Plan ("Executive Plan"); (ii) an Omnibus Incentive Compensation Plan ("Omnibus Plan"), consisting of various stock plans; and (iii) a Non-Executive Incentive Compensation Plan ("Non-Executive Plan"). The Utilities did not dispute proposed disallowances of portions of their Executive Plan expenses and to all of their Omnibus Plan in order to narrow the issues for the Commission's determination. However, the Utilities seek full recovery of the expenses for their Non-Executive Plan.

The Utilities further explain that their Non-Executive Plan sets different annual incentive compensation levels for non-union employees based on four specific performance measures that are all focused on operational aspects of the business. These measures include: cost management weighted at 50%, employee safety weighted at 15%, customer satisfaction weighted at 15% and reliability weighted at 20%. NS Ex. 9.0 at 5-8; PGL Ex. 9.0 at 5-8; NS Ex. 9.1; PGL Ex. 9.1.

The Utilities note that while no party opposes the recovery of costs related to the Non-Executive Plan's employee safety, customer satisfaction and reliability measures which account for 50% of the plan's costs, the AG and CUB-City propose the disallowance of the other 50% of the plan's expenses associated with its O&M cost control measure, which amounts to $439,071 for North Shore and $2,882,076 for Peoples Gas. AG Ex. 1.0 at 29-32; AG Ex. 4.0 at 28-33; CUB-City Ex. 1.0 at 81-98; CUB-City Ex. 2.0 at 15-22.

The Utilities point out that it is a well-established principle that the Commission's standard for recovery of incentive compensation costs, is whether the incentive compensation expenses "can reasonably be expected to provide net benefits to ratepayers." *See In re Illinois Power Co.*, ICC Docket No. 01-0432 (Order Mar. 28, 2002) at 42-43 ("*Illinois Power Co.*"). *See also People ex rel. Lisa Madigan v. Illinois Commerce Comm'n*, 2011 IL App (1st) 100654, ¶¶ 51, 55 (1st Dist. Sept. 30, 2011) ("*Peoples Gas 2009 Appeal*") (holding that the Commission's use of a customer benefit standard for the recovery of incentive compensation costs was appropriate).

The Utilities observe that the Commission disallowed the costs of the same O&M cost control metric in *Peoples Gas 2011*. However, the Utilities contend that the Commission's decision in that case was based on a finding limited to the facts and circumstances in that proceeding that the Utilities had failed to present sufficient evidence to establish the metric was reasonably likely to benefit customers. *Peoples Gas 2011* Order at 57. That decision, limited to the facts in those proceedings, is not binding on the Commission here. The Utilities argue that the facts in this proceeding are distinguishable because the Utilities have adduced specific evidence in the record

demonstrating that the O&M cost control metric does control or reduce O&M expenses which will provide benefits to customers.

The Utilities assert that, as agreed to by Staff, the record evidence contains substantial evidence establishing that the O&M cost control metric can reasonably be expected to provide net benefits to customers as required by the Commission for the recovery of incentive compensation costs. *Illinois Power Co.* at 42-43. The Utilities rely on the conclusion of Staff witness Mr. Ostrander that the Utilities' O&M cost control metric has an established record of reducing or controlling costs since it was adopted by the Utilities starting in the year 2011, resulting in lower O&M expenses for both Utilities in 2011 than in the previous year, and lower O&M expenses than budgeted for the first nine months of 2012 included in the record. Staff Ex. 13.0 at 24-25. The Utilities further rely on Staff's conclusion that the AG's and CUB-City's requested disallowance of the costs associated with the Utilities' O&M cost control metric "are not necessary." *Id*. at 25.

The Utilities point the Commission to specific evidence in the record that they believe demonstrates that the O&M metric provides net benefits to customers. According to the Utilities, the record evidence shows that Peoples Gas was able to beat its O&M expense goal in 2011 by $22.8 million, resulting in an amount of O&M expense that was approximately $2.8 million less than the previous year. Likewise, North Shore was able to beat its O&M expense goal in 2011 by $1.7 million, resulting in an amount of O&M expense that was approximately $1.1 million less than the previous year. NS Ex. 9.0 at 9 -10; PGL Ex. 9.0 at 9-10; NS-PGL Ex. 29.0 at 9. Utilities' witness Ms. Cleary testified that, in her opinion, when costs are reduced or controlled in one year such as they were in 2011, that reduction or control carries through to the basis used in planning the following years' budgets, including the O&M costs budgeted for the 2013 test year at issue in these rate cases. NS Ex. 9.0 at 10; PGL Ex. 9.0 at 10.

While admitting that the Utilities are not able to show a direct link to particular dollars in specific line items of the 2013 O&M budget that have been reduced as a result of the O&M cost control metric (*see* NS-PGL Ex. 45.0 at 5), the Utilities maintain that the hypothetical they presented illustrated how these cost reductions in previous years have benefited customers in the test year budget for the current rate case. *Id*. at 6-7. The Utilities' hypothetical demonstrates that if actual costs for Peoples Gas had not been reduced in 2011, but instead had come in at the budgeted level, the O&M budget submitted by Peoples Gas in this rate case for the 2013 test year may have been over $32 million higher. The hypothetical assumed that the percentage change between this hypothetical 2011 result and the O&M budget for 2012 would have been the same as actually occurred between the real 2011 O&M results and 2012 O&M budget, and then assumed that the percentage change between this hypothetical 2012 O&M budget and the 2013 O&M budget would have been the same as actually occurred between the real 2012 O&M budget and the 2013 O&M budget submitted as part of this rate case. NS-PGL Ex. 45.0 at 6-7. The Utilities assert that this hypothetical shows how costs savings in one year can result in reducing the expenses to be recovered in future rate cases, all else being equal, and supports Ms. Cleary's opinion that without the O&M cost control

metric, the amount of O&M budgeted for the 2013 test year likely would have been higher. NS Ex. 9.0 at 10; PGL Ex. 9.0 at 10; NS-PGL Ex. 45.0 at 7-8. The Utilities point out that even the AG witness Mr. Brosch conceded on cross-examination that increased O&M costs in one year may lead to higher O&M costs being forecasted in a subsequent year's rate case, all else being equal. Tr. at 512-513. The Utilities further argue that this evidence refutes the AG's argument that no direct benefit can be shown to North Shore's and Peoples Gas' customers because the O&M cost control metric payouts are calculated based on a combined Integrys utility basis.

Based on this record evidence, the Utilities conclude that the O&M cost control metric in their Non-Executive Plan falls squarely within the types of incentive compensation plans for which the Commission has allowed recovery in a multitude of cases. A review of past Commission orders reveals numerous instances of the Commission specifically ruling that the costs for a metric which encourages the control or reduction of O&M expenses is beneficial to customers and, therefore, recoverable. For example, in the Utilities' 2007 rate cases, the Commission allowed the Utilities to recover 48.4% of an incentive compensation plan's costs "based on controlling O&M expenses," stating that "we consider this as beneficial to ratepayers." *Peoples Gas 2007* Order at 66-67. Similarly, in Commonwealth Edison Company's ("ComEd") 2005 rate case, the Commission allowed the recovery of expenses for a component of ComEd's incentive compensation plan based on controlling O&M and capital expenses, stating that such a metric "meets the Commission's standard of reducing expenses and creating greater efficiencies in operations," and that "[l]owering O&M expenses, all else being equal, has the obvious effect of reducing the expenses to be recovered in future rate cases." *In re Commonwealth Edison Co.*, ICC Docket No. 05-0597 (Order July 26, 2006) ("*ComEd* 2005") at 95-96. The Commission reached similar conclusions in ComEd's 2007 rate case and other cases. *See Commonwealth Edison Co.*, ICC Docket No. 07-0566 (Order Sept. 10, 2008) ("*ComEd 2007*") at 54-55, 61 (approving recovery of costs for portions of incentive plan identical to those approved in *ComEd 2005*); *Consumers Illinois Water Company*, ICC Docket No. 03-0403 (Order Apr. 13, 2004) ("*Consumers IWC*") at 14-15 (approving recovery of incentive compensation expenses which included a metric for "maintaining or reducing operating costs at or below budgeted levels"); *In re Aqua Illinois, Inc.*, ICC Docket No. 04-0442 (Order April 20, 2005) ("*Aqua Illinois*") at 21-22 (approving recovery of costs for incentive plan similar to the plan approved in *Consumers IWC*).

Nowhere in these decisions, the Utilities argue, has the Commission set a standard requiring a showing of specific line-item cost savings linked to a cost control metric in the exacting detail that the AG and CUB-City would require. Further, the record evidence indicated that there was no methodology known to accomplish such a task, a fact that the AG and CUB-City did not counter. *See* NS-PGL Ex. 45.3, sub (a). The Utilities contend that the *Peoples Gas 2011* is an unusual exception to the Commission's routine approval of such metrics, and it is based on the particular record in that case.

The Utilities respond to the AG's argument that *ComEd 2005* does not support the Utilities' position because it is an historical test year rate case by noting that the Commission's analysis in *ComEd 2005* was not limited to cases involving only historical test years. In fact, the Utilities contend, the Commission in *ComEd 2005* expressly referred to plural "future rate cases" in which customers would benefit from costs being controlled. *ComEd 2005* at 95-96. Moreover, the Utilities assert that the Commission has allowed recovery of costs for incentive compensation metrics designed to control O&M expenses in future test year rate cases, as well. *See Consumers IWC* at 14-15; *Aqua Illinois* at 21-22.

The Utilities also respond to the AG's argument that the costs of the O&M cost control metric should be disallowed because the 2013 test year O&M budget included "much higher O&M expenses." *See* AG Init. Br. at 61. Commission decisions have recognized the principle that lowering costs in one year can reduce costs to be recovered in future rate cases "all else being equal." *See ComEd 2005* at 95-96. As the AG's witness testified on cross-examination, however, all things rarely remain equal for a utility year to year. *See* Tr. at 505, 512-513. Indeed, Utilities witness Ms. Cleary testified that in fact, things had not remained equal for the Utilities since their previous rate cases and those changes caused the test year 2013 O&M budget to increase despite the impact of the O&M cost control metric. Specifically, Ms. Cleary testified that the need for additional compliance work, cross-bore activity and new Chicago Department of Transportation regulations were behind the significant increases in the 2013 test year O&M budget. NS-PGL 45.0 at 8-9. The Utilities argue that as Ms. Cleary testified and as shown by the hypothetical discussed above, these facts do not change the conclusion that the O&M cost control metric provides net benefits to customers because the 2013 O&M budget likely would have been even higher without the cost control incentive provided by this metric. *Id*. at 9.

According to the Utilities, there is also no evidentiary support for the suggestion by the AG that the Utilities may "pessimistically" forecast costs for their test year in order to allow shareholders to benefit from expense savings and the AG cannot point to any such attempt by the Utilities in this docket. The Utilities argue that, on the contrary, their test year budgets are open to scrutiny from not only the AG, but from Staff, other intervenors and ultimately the Commission, thus eliminating the ability of a utility to profit from such a scheme.

The Utilities maintain that the Commission should reject CUB-City's argument that the costs for the O&M cost control metric should be disallowed based on a "double recovery" theory that (a) if costs are controlled or reduced, then the Utilities will over-recover because the costs underlying their revenue requirements would, after the fact, turn out to have been over-stated; or (b) if costs are not controlled or reduced, then the Utilities will recover the costs of incentive compensation for this metric included in their revenue requirements. *See* CUB-City Init. Br. at 40-41. First, Commission practice and policy clearly allows for the recovery of costs for incentive compensation plan metrics that encourage O&M cost control, as demonstrated by *ComEd 2005*, *Peoples Gas 2007*, and the other Commission decisions discussed above. Under CUB-City's

argument, the costs of an O&M cost control metric could never be recovered, because one of these two events must always be the case with respect to an O&M cost control metric, which is contrary to the Commission's policy and practice. Indeed, CUB-City witness Mr. Smith testified that achieving the goal of "cost containment" is a goal "arguably in the interest of ratepayers." CUB-City Ex. 1.0 at 97. Second, CUB-City's argument fails to account for the fact that the benefits from an O&M cost control metric, as explained in *ComEd 2005*, come from controlling or reducing costs in subsequent rate cases.

The Utilities urge the Commission to agree with its position, and the position of Staff, and reject the AG's and CUB-City's proposed disallowance of the costs related to the Utilities' Non-Executive Plan O&M cost control metric.

Staff

Staff recommends that the Commission reject Mr. Brosch's and Mr. Smith's proposed adjustments. Staff avers that the Utilities' rebuttal and surrebuttal testimonies document ratepayer benefits related to their O&M cost control metric, and that recovery of the related incentive compensation costs is consistent with prior Commission practice. Staff Ex. 13.0 at 25. Staff witness Ostrander testified that the Utilities' arguments provide evidence showing ratepayer benefits related to the Non-Executive Plan's costs control metric. The plan results for 2011 for both Peoples Gas' and North Shore's subject O&M expenses were lower than the prior year. NS-PGL Ex. 45.0 at 2-11. In addition, the Utilities' responses to Staff's data requests show that through nine months of 2012, the Utilities' actual expenses were less than the budgeted amounts for the plan's cost control metric. *Id*. For these reasons, Staff argues Mr. Brosch's and Mr. Smith's adjustments are not necessary and should not be adopted.

AG

The AG observes that the Commission has permitted the recovery of incentive compensation costs in rates only when it is demonstrated that such compensation operates to provide identifiable benefits to the utility's customers. The AG argues the Utilities should not be allowed to recover the expenses associated with the Utilities' Non-Executive Plan O&M cost metric primarily because the Utilities' have failed to show that the plan will provide identifiable benefits to ratepayers.

The AG contends that the Utilities have attempted to explain the linkage between achieved O&M savings and rate recovery of incentive compensation primarily by suggesting that estimated test year expenses and the corresponding proposed revenue requirements would likely have been higher absent the incentive compensation program. However, the Utilities admitted that "it is not possible, however, to show a direct link to particular dollars in specific line items of the annual O&M budgets that have been reduced or controlled…as a result of the O&M cost control metric." AG Ex. 1.0 at 30, citing NS-PGL response to AG data request 7.36. In addition, the AG notes that the much higher O&M expenses being proposed by the Utilities in the test year in these

dockets reflect no apparent cost controls either historically or assumed to be exercised in the future.

The AG posits that the Utilities will never be able to demonstrate an observable direct link between forecasted Peoples Gas and North Shore test year adjusted O&M expenses (i.e., the utility customer benefit) and the amounts that drive payouts under the Utilities' Non-Executive Plan as currently constructed because the targeted O&M expenses used to administer the plan consists of a combined "Utility and IBS FERC-based non-fuel O&M" amount from the consolidated budgets of *all* Integrys utility subsidiaries, along with IBS expenses. This large pool of O&M expenses that drives incentive payouts is influenced by O&M performance of multiple Integrys businesses beyond the regulated utilities. Accordingly, not only is the O&M parameter of the plan not tied to expenses included in 2013 rate case forecasted O&M, the payouts under this plan are ultimately driven by a much larger universe of utility operations than just these two Illinois utilities. As such, the AG asserts that the Utilities have failed to demonstrate any kind of identifiable Peoples Gas/North Shore customer benefit associated with the O&M expense element of the plan that may be cultivated by the Integrys utilities in Illinois for ultimate crediting to Peoples Gas and North Shore ratepayers.

The AG challenges Utilities witness Cleary's argument that AG witness Brosch's adjustment is rooted in an objection to the Utilities' selection of a future test year. NS-PGL Ex. 29.0 at 12-13. Clearly, the Utilities are permitted under test year rules to select a future test year. *See* 83 Ill. Admin. Code Part 287.20. But no Commission rule precludes the Utilities from recognizing and including in a future test year forecast the particular savings that must be attributed to an incentive compensation plan for it to be deemed cost effective in controlling O&M expenses. If incentive compensation plans are believed by the Utilities to be effective and incrementally reducing expenses in each year that such incentives are paid, both the cost of the incentives and the benefits produced by the plan, i.e. the corresponding expense savings, must be included within test year forecasts according to the AG.

The AG contends that its proposed adjustment is rooted in the law established in the 2005 ComEd rate case, and the related principle that if incentive compensation costs are being allowed based upon the premise that cost control metrics within the incentive plan are cost-effective, one of two outcomes should be required whenever a forecasted test year is employed. Either the Utilities should be able to demonstrate with specificity that forecasted test year expenses have been directly reduced incrementally for the expected amounts of future cost savings that will be induced by 2013 payments of incentive compensation, or, alternatively, if such direct reductions for incentive plan driven O&M savings have not been demonstrated to exist within the rate case expense forecast, the Utilities' shareholders should bear the cost of the cost-control portion of incentive compensation, because they alone will benefit when and if such savings occur in 2013. The AG argues shareholders alone will benefit because the relevant O&M savings are not reflected in rate case forecasted O&M.

The AG observes that the Utilities reference the 2005 ComEd rate case where the Commission is said to have concluded, "…that expenses for incentive compensation metrics that encourage O&M cost control benefit customers because '[l]owering O&M expenses, all else being equal, has the obvious effect of reducing the expenses to be recovered in future rate cases'." NS-PGL Ex. 29.0 at 13. However, the AG argues the Utilities' reliance on this case is not helpful because the Utilities fail to acknowledge that in 2005, ComEd's rates were being set based upon historically incurred costs, which would automatically include any and all experienced cost savings that were caused by the recorded amounts of incentive compensation costs in the historical test year. In such an environment, ratepayers are assured of participation in recorded expense savings resulting from cost-effective incentive compensation plans that result in actual cost reductions. Additionally, because ComEd's expenses were not based upon a forecast, there was no need to verify that incentive plan-driven expense savings were not being ignored in developing the forecast. AG Ex. 4.0 at 32.

The AG asserts that the instant case is quite different than the 2005 ComEd rate case. Here a forecasted test year is being employed. The O&M amounts in the test year forecasts of each utility are estimated, such that there is no assurance that any future expense savings that may be realized because of incentive compensation-driven cost controls will ever be shared with ratepayers. In addition, the AG asserts that utility management has every incentive to pessimistically forecast its costs in the forecasted test year and then keep for shareholders any actual expense savings that may later appear within recorded financial results. *Id.*

The AG contends that the Utilities have failed to demonstrate that any future test year expense savings expected to be caused by 2013 incentive payments have been forecasted, which is why the AG believes O&M incentives should not be recovered from customers. The AG also maintains that incentive plan-driven annual expense savings of 1.66% still represent more than three times the 0.5% productivity adjustment proposed by the AG in Section V.C.6. herein.

For all of the reasons cited above, the AG proposes that the Commission disallow the forecasted expenses associated with the Utilities' Non-Executive Plan O&M cost metric.

CUB-City

CUB-City concur with the AG and recommend that the Commission disallow the O&M expenses related to the Utilities' cost control metric. CUB-City note that the Commission did not allow the Utilities' to include Non-Executive Plan costs related to this same type of metric in the Utilities' last rate case.

CUB-City argue these expenses should be disallowed for two reasons. First, the Utilities failed to show that the metric has a net benefit to ratepayer; in other words, the incentive compensation payout under the metric may exceed the "savings" on which they are based. Second, the recovery of incentive compensation related to this metric would result in double-recovery for the Utilities since the Utilities would recover their full

2013 O&M budget, although actual spending is lower than projected for ratemaking purposes, while also recovering through rates the incentive compensation paid out as a result of beating that budget.

The Metric Has No Net Benefit for Ratepayers

CUB-City aver that the award of Non-Executive Plan compensation based on O&M cost control should only be charged to ratepayers if the Utilities can demonstrate that ratepayers are obtaining a net benefit, a point with which the Utilities apparently agree at least conceptually. CUB-City point out that the Utilities' Vice President Mr. Schott conceded that the amount of incentives paid under the incentive compensation program should not exceed the savings created by such incentives. Tr. at 400. CUB-City aver that the O&M metric in the plan is intended to produce O&M savings through productivity gains, but the Utilities have not reflected the impact of such productivity gains as an offset against their 2013 test year forecasts. CUB-City Ex. 2.0 at 17. CUB-City explain that the Utilities have not demonstrated that productivity gains will be achieved as a result of the O&M metric of the Non-Executive Plan, or that those gains will exceed the Non-Executive Plan cost. CUB-City state that if productivity gains are not achieved, then the metric is not cost-effective or prudent. *Id*. at 18.

CUB-City observes that although the Utilities argue that their selected metrics have been effective in achieving cost savings, their O&M expenses are, in fact, increasing significantly. CUB-City Ex. 2.0 at 17. The Utilities' position is that the O&M cost control metric generally reduces the level of expenses that will need to be recovered in future rate cases, because budgets tend to build on each other. NS-PGL Ex. 25.0 at 5. However, CUB-City point out the Utilities' admission that that it is not possible to show a direct link to specific savings as a result of the O&M cost control metric. *Id*. Indeed, it would be difficult to do so, since their O&M budget has, by their own calculations, significantly increased year-over-year despite the existence of the O&M cost control metric. *See* NS-PGL Ex. 45.0 at 6. Peoples Gas projects a 9% O&M increase for 2013 over its 2012 budget. *Id*. CUB-City avers that the Utilities cannot point to any place where they have reduced the 2013 budget to account for this metric, Tr. at 130, and the budgeted 9% increase suggests that insufficient O&M savings are being reflected in the Utilities' proposed revenue requirement. CUB-City Ex. 2.0 at 18.

The Utilities' Proposal Results in Double-Recovery

CUB-City explain that in the event that the Utilities, and IBS as a whole, do beat their 2013 O&M budgets, there is no mechanism to pass those savings on to ratepayers. Tr. at 129. CUB-City note that in this proceeding, the Commission will approve a 2013 revenue requirement that assumes that the Utilities meet, but do not beat, their 2013 O&M budget. However, CUB-City aver, the Utilities seek to recover their 2013 O&M budget, as well as incentive compensation pay-outs that assume the Utilities have, in fact, spent less than the O&M budget they propose should be included in rates. CUB-City maintain that if the Commission approves recovery of both the entire 2013 O&M budget and the Non-Executive Plan payout costs, the Utilities will over-

recover. CUB-City state that if the Utilities achieve their "cost control" goals, and spend less than their budgeted O&M, the Utilities (and their shareholders) retain the savings. If the Utilities do not achieve their "cost control" goals, and the Non-Executive Plan is not paid out, the Utilities (and their shareholders) retain the amount included in their revenue requirement based on the assumption that it would, in fact, be paid out. Tr. at 137. In either scenario, CUB-City state, the Utilities over-recover their actual costs, and the resulting rates are not just and reasonable. In fact, since the Utilities acknowledge that savings should exceed incentive compensation payouts, under that standard the Utilities still over-recover, by retaining the savings net of the incentive compensation payouts for themselves, not ratepayers.

CUB-City point out that the Utilities agree that the amount of incentives paid under the incentive compensation program should not exceed the savings created by such incentives.Tr. at 400. The Utilities further admit that they could pay for the incentive compensation related to this metric out of the savings retained from beating their O&M budget. Tr. at 129. CUB-City maintain that is what the Commission should require. Requiring ratepayers to fund this incentive compensation plan expense, which may or may not be paid out (and if it is paid out, it will be because the Utilities saved money elsewhere) is not just and reasonable. CUB-City aver that the incentive compensation cost could and should be paid out of the retained savings from which it is derived.

CUB-City therefore request that the Commission adopt the AG's proposal to disallow of the Utilities' Non-Executive Plan costs associated with the O&M cost control metric.

Commission Analysis and Conclusions

The Commission finds that the expenses related to the Utilities' O&M cost control metric which consist of 50% of the Utilities' Non-Executive Plan's costs are reasonable, prudent, and reasonably expected to benefit ratepayers. Unlike in the Utilities' last rate cases, the Utilities provided sufficient evidence in this proceeding to establish that the O&M cost control metric can reasonably be expected to provide benefits to ratepayers. The Commission has a long-standing policy of allowing incentive compensation costs when those costs benefit ratepayers. One of the goals that the Commission encourages public utilities to incentivize through such plans is the control and reduction of operating costs since, as the Commission concluded in the *ComEd 2005* and *Peoples Gas 2007* decisions, this should have the effect, all else being equal, of lowering the costs to be recovered in future rate cases. The Utilities' O&M cost control metric has now been in place since 2011 and it's performance history clearly demonstrates that the metric has been effective in reducing or controlling costs which the Commission continues to believe is beneficial to ratepayers. Additionally, the recovery of these expenses is consistent with prior Commission treatment of costs associated with such metrics. Accordingly, the proposal by the AG and CUB-City to disallow this portion of the Utilities' Non-Executive Plan is rejected.

2. Wage Increase Correction

Utilities

The Utilities note that Staff filed revised Schedules 13.02 N and 13.02 P purporting to "correct" capitalized construction wages to reflect an average year impact and the ADIT Adjustment. Tr. at 243. With respect to capitalized construction wages, the Utilities take the position that rates should be set using a year-end rate base methodology. The Utilities agree that the changes to Staff's proposed adjustment set forth in Staff's revised Schedules 13.02 N and P would be the correct amount of the adjustment *if* the Commission accepts Staff's proposed disallowances to the non-union wage base increases *and if* the Commission agrees that an average year rate base methodology is appropriate. The Utilities, however, argue that the Commission should reject both of Staff's proposals, as discussed in Section V.C.3, *infra*, with respect to non-union base wages and in Section IV.C.1, *infra*, with respect to using a year-end rather than an average rate base methodology.

The Utilities do not object to Staff's correction of the derivative ADIT adjustment for non-union wages for Peoples Gas (from ($3,000) to $7,000) on line 13 of revised Scheduled 13.02 P.

Staff

Staff states that it filed revised Schedules 13.02 N and 13.02 P to correct capitalized construction wages to reflect an average year impact and the ADIT Adjustment. Staff's revision to its Schedules 13.02 N and P adds a column (f) for line 8 on the first page of the schedules to show that *if* the Commission adopts an average year methodology as urged by Staff, Staff's proposed downward adjustment for non-union wages should be divided by 2 for the capitalized construction component of non-union wage base (changing the proposed downward adjustment to this component from $61,000 to $31,000 for North Shore and from $1,137,000 to $569,000 for Peoples Gas).

Staff's revised schedules also correct the derivative ADIT adjustment for non-union wages for Peoples Gas (from ($3,000) to $7,000) on line 13 of revised Scheduled 13.02 P.

Commission Analysis and Conclusions

The Commission finds that Staff's proposed corrections to capitalized construction wages to reflect an average year impact are reasonable and approved. These corrections are consistent with the Commission's approval of Staff's proposed adjustment to the Utilities' non-union wage base increase and the Commission's approval of the average year rate base methodology in this Order.

The Commission also approves Staff's proposed correction of the derivative ADIT adjustment for non-union wages for Peoples Gas (from ($3,000) to $7,000). This correction was not contested.

3. Non-union Base Wages (Falls in Multiple Categories of O&M)

Utilities

North Shore and Peoples Gas propose an increase in their rate bases and operating expenses for the 2013 test year to allow for a general wage increase (2.60%), a pool of funds to provide for merit-based increases to be given only to high-performing employees (0.45%), and a pool of funds to provide for costs attributable to pay increases commensurate with promotions and market adjustments given only to certain employees (0.40%). NS-PGL Ex. 29.0 at 18. The total amount of this requested increase is equal to 3.45% of the Utilities' total non-union base wages. *Id*. at 17-18.

The Utilities oppose Staff's recommendation to reduce the overall amount of this increase to 2.28% of the Utilities' total non-union base wages for 2013 based on reducing the Utilities' proposed general wage increase component using a forecast of the Consumer Price Index ("CPI") and completely disallowing both the amount to be used for merit increases and the amount to be used for raises due to promotions. Staff Ex. 3.0 at 12-14; Staff Ex. 13.0 at 9-13.

The Utilities first dispute Staff's contention that its position is supported by the fact that the Commission accepted a similar adjustment in the Utilities' last rate cases. The Commission's decision in *Peoples Gas 2011* is not determinative of this issue. It is well-established that the Commission is not bound by its past decisions and must make its determination based on the facts and circumstances particular to each case before it. 220 ILCS 5/10-103; 220 ILCS 5/10-201(e)(iv)(A). *See also Citizens Util. Bd.*, 166 Ill. 2d at 125-126; *Mississippi River Fuel Corp.*, 1 Ill. 2d at 513. The Utilities posit that this principle is exceptionally apt here because the Utilities have submitted new evidence demonstrating the flaws in Staff's position.

The Utilities state that one of the main flaws of Staff's proposal is that it treats the overall increase in the Utilities' non-union wage base as a whole, when in fact it is comprised of three separate components. The Utilities state that the problem with this approach is that it fails to address the record evidence supporting each of the individual components of the Utilities' non-union wage base increase. The Utilities contend that this divide between the record evidence and Staff's proposed adjustment means that the adjustment lacks the support of substantial record evidence and should fail for this reason alone.

Peoples Gas and North Shore further address each of the three components of their non-union wage base increase individually.

General Wage Increase

The Utilities assert that Staff's proposal is inappropriate for at least three reasons. First, the CPI is not a measure designed or intended to predict or be used to set wage increases, but rather, is an economic indicator calculated by the Bureau of Labor Statistics ("BLS") to show a change over time in the prices paid by consumers for

a market basket of goods and services. NS-PGL Ex. 29.0 at 19-20 and n. 4; NS-PGL Ex. 45.0 at 12. Further, the CPI forecast covers a five-year period (2012-2016) rather than the single year of 2013 which means that it includes a measurement of CPI for a period of time outside the 2013 test year to determine the general wage increase which is inconsistent with some of Staff's arguments concerning the average versus year end rate base issue. Moreover, the Utilities assert that Staff's statement that this "forward looking projection is more in line with the period that rates will be in effect" lacks any support in the record evidence, and contradicts Staff's arguments on the average rate base issue also. This statement is also incorrect as a matter of law, the Utilities argue, in light of the fact that the Utilities will be required to file another rate case no later than the year 2014 pursuant to the requirements of Section 9-220(h-1).

Second, the forecast for CPI, which is a broad measure that is not differentiated by industry or service type, will likely under-predict the level of change that actually will occur in an industry changing at a faster pace than the market on average. The BLS' Employment Cost Index ("BLS Index") presented by the Utilities is specifically designed to measure changes in wages and salaries by industry, and it reveals that wages in the utility industry have been increasing at a faster pace than overall wages generally (2.3% versus 1.5% for the twelve months ended September 2012). NS-PGL Ex. 29.0 at 20 and n. 5; NS-PGL Ex. 45.0 at 12-13 and n. 5.

Third, the Utilities' proposed general wage increase is based on market data provided by the World At Work 2012-2013 Salary Budget Survey, which is a well-known compensation tool that reports results of annually surveyed information submitted by corporations on their planned wage increases for the following budget year. NS-PGL Ex. 29.0 at 17; Tr. at 251. The research data from this survey shows that average wage increases for 2013 will be in the "high 2% range" – 2.90% which the Utilities argue demonstrates that their proposed general wage increase is well below the market average.

North Shore and Peoples Gas conclude that the 2.60% general wage increase proposed by the Utilities is supported by the substantial weight of the record evidence as being a just and reasonable market-based amount for a general wage increase for their non-union employees in 2013.

Pool of Funds for Merit Based Increases

The Utilities state that the divergence between the record evidence and Staff's proposal is greatest with respect to the second component of the Utilities' non-union wage base increase – merit based increases. The Utilities introduced new evidence supporting the recovery of this component of non-union wage base increase not considered by the Commission in the Utilities' previous rate cases. The Utilities contend that this evidence demonstrates not only a possible misunderstanding of this component by Staff, but that the purpose of this component is in fact consistent with Staff's opinion as to appropriate wage increases for high-performing employees.

The Utilities note that Staff witness Mr. Ostrander testified on cross-examination that he has no objection to a public utility giving a larger pay increase to individual employees who perform at a higher level than other employees. Tr. at 250. Mr. Ostrander also acknowledged that the market research data from the World At Work survey demonstrates that top performing employees may receive wage increases of up to 4.0% in 2013, and testified that he has no reason to doubt this conclusion. *Id*. at 250-252; Staff Ex. 13.0 at 13. The Utilities contend that Staff's proposed disallowance of this component of non-union wage base increase is inconsistent with Mr. Ostrander's testimony concerning the compensation of high-performing employees. The Utilities further argue that it seems the two grounds Staff relied upon for its recommended disallowance of this component are based on misunderstandings concerning the facts of how this pool of funds is used to provide individual merit-based increases to the Utilities' high-performing employees.

First, Staff based its position on the assumption that the Utilities may not actually award the full amount of the merit-based increases, believing that the Utilities only used half of the amount of such funds forecasted in their 2011 rate cases for 2012. Staff Ex. 13.0 at 12. As was clarified at the hearing, however, Staff's assumption was incorrectly based on combining the amounts forecasted for both the merit-based component and the component for providing raises due to promotions. Tr. at 254-255, 257-258; NS-PGL Cross Ex. 3. The undisputed evidence demonstrated that the full amounts forecasted to be used for merit-based increases to top-performing employees in both 2011 and 2012 (0.3% and 0.45%, respectively) were in fact used by the Utilities. Tr. at 258-259; NS-PGL Ex. 45.5. This was consistent with the record evidence establishing that the Utilities have no discretion on whether or not these funds will be used because the full amount of this pool of funds is automatically distributed to award individual merit-based increases to high performing employees. NS-PGL Ex. 45.0 at 14; NS-PGL Ex. 45.4.

Second, Staff relied on the assumption that all non-union employees received this 0.45% increase. Staff Ex. 13.0 at 12-13. The Utilities state the evidence clearly shows that while the total amount of this pool of funds is calculated based upon an overall percentage (0.45%) of the Utilities' total non-union wage base, those funds are used to award additional increases only to particular individual employees who perform at a high-level by receiving exemplary performance reviews. NS-PGL Ex. 45.0 at 14; NS-PGL Ex. 45.4; Tr. at 252-254. Indeed, this result is consistent with Mr. Ostrander's view that a higher-performing employee deserves a larger raise relative to an average employee. Tr. at 250.

The Utilities conclude that all of the record evidence establishes that this component of the Utilities' non-union wage base increase is consistent with Staff's views on employee compensation and appropriate under the facts and circumstances of these dockets. The Utilities thus urge the Commission to reject the proposed elimination of this component from the Utilities' non-union wage base increase.

Pool of Funds for Raises Due to Promotions

The Utilities observe that Staff recommends disallowing this component of non-union wage base increase on the same grounds as the merit-based wage increase component discussed above. The Utilities state that, as with the merit-based increase component, this pool of funds for promotional-related wage increases is not awarded to all employees, but rather, only to specific employees who have received promotions where a commensurate increase in pay for the new position is appropriate. NS-PGL Ex. 45.0 at 15.

This pool of funds for promotions – unlike the merit-based increase pool of funds – is discretionary in nature. *Id*. at 14-15; NS-PGL Ex. 45.4. Still, the Utilities assert that they are expected to use this entire pool of funds appropriately to keep and maintain a high-quality workforce and ensure that each necessary position is filled by a highly-qualified employee receiving a market-based rate of pay. NS-PGL Ex. 45.0 at 15. Because the use of these funds has been discretionary, however, the Utilities offer an alternative position in which they request that the Commission award recovery for this pool of funds equal only to the amount by which such increases accounted for a percentage of the Utilities' total non-union wages in 2012: 0.154% for Peoples Gas and 0.007% for North Shore. *Id*.; NS-PGL Ex. 45.6.

Staff

Staff urges the Commission to accept Staff's adjustment to reduce the amount of non-union wage increases to a more reasonable amount. Staff's adjustment is calculated using the 3% non-union wage increase granted in February 2012 for 2012 non-union wage increases and the 2012-2016 CPI inflation rate of 2.28% as forecasted by the Survey of Professional Forecasters for the 2013 non-union wage increases. Staff used these rates to escalate the Utilities' 2011 actual non-union base wages to determine test year non-union base wages. Staff Ex. 3.0 at 12.

Staff notes that in rebuttal testimony, the Utilities offered the World at Work Salary Budget Survey as support for the 2013 test year non-union wage increase of 3.45%. NS-PGL Ex. 29.0 at 17-18. This source is the same source that was used by the Utilities in the 2011 rate cases, which was rejected by the Commission. Staff Ex. 13.0 at 10. Staff argues that the Commission should reject the World at Work Survey again. Staff bases its recommendation on the Survey of Professional Forecasters rather than World at Work Survey results since it is a more forward-looking study projecting 2012-2016 increases. This forward looking projection is more in line with the period that rates will be in effect, rather than the single year (2012-2013) projected in the World at Work Survey. The Utilities, however, cite the BLS Index as support for their position. Staff opines that even though the BLS Index is a backward looking study, its results support the reasonableness of Staff's position in that it also measured a 2.3% wage increase for the utility industry for the 12 months ended September 2012. Staff Ex. 13.0 at 11. Staff maintains that based on the evidence in the record, its adjustment to reduce the amount of non-union wages increases to a more reasonable amount based upon the CPI forecast is appropriate and should be adopted by the Commission.

CUB-City

CUB-City recommend that the Commission adopt Staff's proposed adjustment. CUB-City state that the Utilities project an increase of 3.45%, even when the 2012-2016 CPI inflation rate is forecasted to be only 2.28%. Staff Ex. 13.0 at 9. CUB-City explain that Staff witness Mr. Ostrander used the CPI rate to escalate the Utilities' 2011 actual non-union base wages to determine test year non-union base wages. *Id*. at 9-10. CUB-City note that the Utilities' proposed methodology is the same as that proposed by the Utilities in their last rate case, which was rejected by the Commission. *Id*. at 10. CUB-City argue that the evidence in the instant record demonstrates that the Utilities' projected wage and salary escalation is not reasonable, as even the Utilities' own cited support, the BLS Index, shows that during the 12 months ending September 2012, wages and salaries increased only 2.3%. *Id*. at 11. CUB-City therefore supports Staff's proposed adjustment because it produces a reasonable non-union base wage increase, unlike than the Utilities' unsupported and inflated estimates.

Commission Analysis and Conclusions

Staff's recommended adjustment to change the increase proposed by the Utilities to 2.28% for the 2013 test year rather than the 3.45% proposed by the Utilities is reasonable and adopted. Staff's proposed adjustment for 2013 is based on the 2012 through 2016 CPI inflation rate of 2.28% as forecasted by the Survey of Professional Forecasters. The Commission believes the Survey of Professional Forecasters, which forecast projections of increases for 2012 through 2016, provides a more reasonable estimate of non-union wage increases that appears to more accurately match market conditions during the period the rates will be in effect than the World at Work Survey which reflects projections for increases for a single year. Moreover, the Utilities' own cited support, BLS Index, shows that during the 12 months ending September 2012, wages and salaries increased only 2.3%. Accordingly, the Commission declines to adopt the Utilities' proposed levels of non-union wage base increases.

4. Vacancy Adjustment (Falls in Multiple Categories of O&M)

Utilities

The Utilities' argue that their 2013 payroll expenses should not be reduced as the AG and CUB-City propose for a vacancy factor because the Utilities' employee levels will be equivalent to their forecasted employee levels. The Utilities are actively filling their budgeted and forecasted positions in order to equal the headcounts reflected in their test year operating expenses. PGL Ex. 8.0 at 14-16; NS-PGL Ex. 28.0 Rev. at 13-14; NS-PGL Ex. 44.0 at 10-11. Peoples Gas is filling positions that were added to equal the headcounts reflected in its test year operating expenses. NS-PGL Ex. 28.0 Rev. at 13-14. As of November 24, 2012, North Shore was only two positions below its budgeted headcount and was in the process of hiring to fill its two empty positions. NS-PGL Ex. 28.0 at 13. Moreover, the Utilities argue the AG and CUB-City positions ignore the fact that the Utilities can prepare to fill a position when an employee's departure is known in advance. Furthermore, if the same amount of work is done by a reduced

number of employees, increased overtime and/or additional outside labor may be utilized, which the Utilities have done from time to time as need, which results in increased costs. PGL Ex. 6.0 at 6. For these reasons, the Utilities argue the payroll expenses should not be reduced.

Staff

Staff argues that its proposed adjustment to the Utilities' non-union wages, which is discussed above in Section V.C.3., has an impact similar to a vacancy factor adjustment. To calculate test year non-union wages, Staff escalated the 2011 actual non-union wages by the general wage increase given in 2012 and by Staff's recommended percentage increase for 2013. Staff's calculated test year non-union wages did not include the impact of wage increases for the forecasted additional headcount for 2012 and 2013. Staff Ex. 3.0, Scheds. 3.03 N and P at 3. Staff argues that consistent with its recommendation above in Section V.C.3, Staff's adjustment to decrease non-union wages to a more reasonable amount is appropriate and should be adopted by the Commission. Staff notes that it did not adjust the union wages for a vacancy factor.

AG

The AG proposes a vacancy adjustment to the Utilities' O&M expenses in the amount of $7,550,000 in the case of Peoples Gas and $837,000 in the case of North Shore. AG Ex. 4.1, Sched. C-2; AG Ex. 4.2, Sched. C-2. The AG argues the Commission should adopt this proposal because it presents a more reasonable and more realistic projection of the Utilities' actual test year spending for labor, benefits and payroll tax expenses, based upon the known and measurable reality that turnover within the workforce and unavoidable delays in the process of filling positions creates a normal and ongoing level of vacancies in actual staffing levels. AG Ex. 1.0 at 18. The AG submits that the proposed adjustment is a conservative and necessary offset to the massive and largely unsupported increase in staffing and labor-related expense that is proposed for Peoples Gas in the test year. The AG believes that if a normal level of employee vacancies is not injected into the Utilities' vastly increased staffing and labor and benefit expense forecasts, ratepayers will clearly be burdened with overstated expense estimates.

The AG notes that an analysis conducted by AG witness Mr. Brosch revealed that the Utilities have overstated the number of employees they expect to add in the test year and then unrealistically presume that no vacancies will occur at the higher proposed staffing levels. Peoples Gas' forecasted staffing level for the 2013 test year stands in stark contrast to an average of its actual staffing levels for summer 2012. *See* AG Ex. 1.0 at footnote 13. Of primary concern to the AG is that the Utilities started with their actual staffing levels as of the time of preparation of the forecast and simply added personnel where they believed expansion was needed. This is problematic, particularly because the Utilities are projecting what Mr. Brosch deemed a "highly unusual" 24% rate of growth to staffing in merely two years. AG Ex. 1.0 at 16. Mr. Brosch reasoned that Peoples Gas' projections are not reasonable especially in light of the fact that

Peoples Gas proposed a similar level of staffing for 2012 but failed to meet the forecasted levels. AG Ex. 1.0 at 18.

The AG points out that the actual hiring decisions are largely within the control of utility management. It is quite possible for a utility to forecast a level of authorized positions and then decide to not fill, or delay the backfilling, of some of the forecasted positions. Vacant positions are a reality of business operations and given these realities, it is unreasonable to anticipate anything other than a "normal" level of vacancies among approved staff positions. The AG maintains that the Utilities, however, unrealistically assume that every forecasted new and existing authorized employee position will be filled by an active employee throughout the test year. PGL Sched. G-5, NS Sched. G-5. The AG argues that given the impossibilities of achieving and maintaining full staffing of every position, the Utilities' position that there will be no vacancies among its projected higher authorized staff count is unreliable and unrealistic and should be disregarded by the Commission.

The AG also argues that the Utilities' increased staffing level projections lack substance and have not been justified. In particular, Peoples Gas projects adding 263 employees to its AMRP and to implement a company-wide reorganization. This proposed dramatic staffing level increase becomes problematic for ratepayers because higher labor-related expenses mean higher gas rates and the Utilities have simply not justified these higher expenses. Despite numerous requests during the discovery phase of this docket, the Utilities did little to actually justify the need for proposed staffing level increases. Peoples Gas responded with little more that high level analyses and incremental labor demand estimates. *See* AG Ex. 1.5. Moreover, the Utilities submitted no direct testimony and little documentation to support a 24% burst in Peoples Gas staffing. The AG states that if the Utilities truly need to employ additional workers in order to deliver safe, reliable, and effective service, it is realistic to expect some quantitative showing of why the proposed number of added personnel is prudently needed. However, the AG asserts that the failure of the Utilities to justify proposed staff count increases leaves the Commission with no alternative other than to either reject the Utilities' labor cost increase projection in total, or to adopt the conservatively quantified offset for a reasonable estimate of ongoing employee vacancies as proposed by AG witness Brosch.

Mr. Brosch proposed an adjustment for each utility that reflects an historically calculated "average vacancy factor" for Utility and IBS employees based on actual compared to authorized numbers of employees throughout 2012. Mr. Brosch calculated the proposed vacancy factors by using the Utilities' own historical data. He divided the number of authorized but unfilled employee positions during January through September 2012 by the total number of authorized positions in each month. The AG notes that Mr. Brosch's analysis accepted the premise that the Utilities' forecasted targeted numbers of employees will actually be needed to run the business in the test year, in the absence of any real proof of such need, while offsetting forecasted labor costs only to recognize the reality that actual staffing levels will not fully achieve targeted staffing levels. AG Ex. 1.0 at 20.

The Utilities argue that the vacancy rate adjustment proposed by Mr. Brosch is based upon "snapshots" of employee counts that do not reflect existing and future additions to employee counts. NS-PGL Ex. 4.0 at 14. However, the AG maintains that what is notably absent from the Utilities' response is any proof that its proposed future additions to employee counts or the many existing positions will remain filled throughout the 2013 test year without any occasional vacant positions arising from normal workforce turnover. Peoples Gas also attempts to explain away the reality of employee turnover and vacancies by citing to its training school. However, as Mr. Brosch testified, "The need to create a 'school' to train and hire new employees is indicative of the challenges associated with attracting and retaining qualified staff even in periods of relatively high unemployment." AG Ex. 4.0 at 17. Additionally, the fact that, at the time that the Utilities filed their rebuttal testimony, North Shore was two positions below its targeted staffing levels should not influence the Commission. This is merely another of the Utilities' "snapshots" that fails to account for unplanned vacancies throughout the year. It is the AG's view that failing to properly account for these inevitable vacancies will cause Illinois ratepayers to overpay for salaries and benefits for employees that, at various points throughout the year, simply do not exist.

The AG points out that other state's Commissions have adopted similar employee vacancy factors to reduce forecasted labor and benefit expenses. As an example, the Hawaiian Commission, over the last several years, approved and adopted vacancy factors ranging from 2.68% to 7.31%. AG Ex. 4.0 at 19. The AG argues that it is essential that the Peoples Gas vacancy rate adjustment be adopted to improve the credibility of the Utilities' largely unsupported test year forecasts of labor-related expenses driven higher by proposed staffing increases, by injecting a conservatively quantified offset for vacant positions that certainly will be experienced among the authorized staffing levels that are unrealistically assumed to be 100% filled and paid throughout the test year.

The AG also notes that Staff did not adopt the AG's adjustment and unlike the AG, Staff did not conduct any independent analysis of employee vacancy rates. The AG maintains that its proposal was conservatively crafted, reflective of business realities, and should be adopted by the Commission.

CUB-City

CUB-City aver that in any company the size of Peoples Gas or North Shore, it is common to have work force vacancies at a given point in time. CUB-City Ex. 1.0 at 48. Vacancies occur, and some time lag between the vacancies occurring and the positions being filled also occurs. However, in projecting their labor costs, the Utilities assumed that every budgeted position was filled throughout the 2013 test year. CUB-City maintain that is an unrealistic projection for any large company, particularly in light of the fact that the actual level of filled positions was substantially below the Utilities' budgeted work force levels in each month of 2012 through September. *Id*. at 50. Moreover, the Utilities' 2013 projections include additional positions, above the 2012

budgeted levels. CUB-City Ex. 2.0 at 23. Since the Utilities have historically been running substantially under their budgeted level of FTEs (CUB-City Ex. 2.0 at 23), CUB-City finds it even less likely that the Utilities' will actually incur projected costs based on every old and new position being filled as of January 1 and remaining filled throughout the year to December 31.

CUB-City witness Mr. Smith calculated a vacancy adjustment for each company by averaging their actual percentage of vacant positions for the first nine months of 2012. CUB-City Ex. 1.0 at 51. January 1 – September 30, 2012, North Shore averaged 4.5 vacant positions—a vacancy rate of approximately 2.661%. *Id*. at 51. During that time, the budgeted average of IBS full-time equivalent ("FTE") positions allocated to North Shore averaged was 1,370, but the actual filled positions averaged only 1,313—a difference of 57 vacant positions, or a vacancy rate of 4.1450%. *Id*. at 51.

From January 2012 through September 2012, Peoples Gas averaged 72.5 vacant positions, a vacancy rate of approximately 5.6%. The budgeted average of IBS FTE positions allocated to Peoples during that time was 1,365, though the actual FTEs were only 1,307—leaving 58 vacant FTEs.

CUB-City argue that a more reasonable methodology is to use an average of the "open positions" that the Utilities had not filled at the beginning of the test year, but might fill by the end of the test year. *Id*. at 23. This is consistent with the use of an average test year, reflecting that open positions are filled gradually during the 2013 test year. *Id*. at 491-98. Given the remoteness of the Utilities' assumption of 100% fill for 365 days, an average that acknowledges the reality of vacancies is the more accurate, realistic projection.

CUB-City note the Utilities' complaints that an adjustment for vacancies should not include pensions and postretirement benefit costs, which would not be relevant to new hires, are misplaced, as Mr. Smith had not included those items in the quantification of employee benefits for his vacancy adjustment. CUB-City Ex. 2.0 at 24.

CUB-City recommend the Commission acknowledge the fact that the Utilities will have vacancies throughout the year, and adopt Mr. Smith's adjustment.

Commission Analysis and Conclusion

The Commission believes the Utilities' projections of employee headcount for 2013 are reasonable and supported by the evidence in the record. The Utilities have justified their forecast, noting that the primary drivers of their increased headcount are their improved compliance with federal and state pipeline safety regulations and AMRP. The record demonstrates that the Utilities are making efforts to fill their budgeted and forecasted positions to meet their test year projections. Many of the positions that Peoples Gas has forecasted have been filled, including most of the positions added in response to AMRP. Moreover, as of November 24, 2012, North Shore was two positions below its budgeted headcount and it was in the process of hiring for both of

these positions. The Commission also notes that the Utilities have explained that Peoples Gas' headcount for 2012 did not meet its budgeted level due to the unanticipated length of time it took to establish the school it partnered with the City Colleges of Chicago and the UWUA Power for America Training Trust Fund at the Dawson Technical Institute in Chicago to open to train future Peoples Gas workers. Peoples Gas has been hiring the graduates of this school since it was opened recently as full time employees allowing it to add utility workers to its workforce at a faster pace. It appears Peoples Gas' headcount will equal its budgeted level with the addition of the graduates that it plans to hire from this school. Accordingly, the Commission finds that the Utilities' employee levels will be equivalent to their forecasted employee levels and the Commission declines to adopt the AG's and CUB-City's proposed adjustment to the Utilities' payroll expenses for a vacancy factor.

5. Distribution O&M

a. Plastic Pipefitting Remediation Project

Utilities

Peoples Gas explains that its Plastic Pipefitting Remediation Project ("PPRP") involves replacing certain plastic fittings within the Peoples Gas system which may not have been in technical compliance with Part 192 of Title 49 of the Code of Federal Regulations. Peoples Gas argues that Staff's recommendation to disallow the O&M expenses related to the PPRP should be rejected as Peoples Gas has presented evidence that the plastic fittings were safe, and that a special permit under the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), if applied for, would have been granted even after installation of the fittings.

Peoples Gas asserts that an external and industry-recognized expert performed an extensive analysis on the pipe fittings and concluded that they were safe. NS-PGL Ex. 28.0 Rev. at 12. The expert further concluded that Peoples Gas could have sought a permit as allowed under Title 49 of the Federal Rules. *Id.* This evidence is unrebutted according to Peoples Gas. However, Peoples Gas decided to replace the fitting at this time given its ability to coordinate some of replacement with other scheduled work. *Id.* at 12. Furthermore, it notes that Staff only cites one violation of the federal rules – that the fittings were not properly marked in accordance with Section 192.63, which does not impact the safety or integrity of the fittings. NS-PGL Ex. 44.0 at 6. Also, while Staff claims that an operator must apply to PHMSA for a special permit before installing non-compliant equipment, Peoples Gas argues that sub-section 194.341(b) of the federal rules does not so require. *Id.* Sub-section 194.341(b) provides that an operator must submit an application for a special permit at least 120 days prior to the effective date of the granting of the special permit. *Id.* Peoples Gas argues the terms and contents of the application for a special permit also do not support Staff's assertion. *Id.* Additionally, Peoples Gas notes that PHMSA has entertained and granted applications for special permits after non-compliant work has been installed. *Id*. at 7.

Staff

Staff recommends that Peoples Gas' O&M expenses be reduced by $2,000,000 to exclude all costs related to the PPRP. Staff Ex. 16.0 at 1. Staff witness Brett Seagle testified that in his opinion, Peoples Gas failed to demonstrate that the costs associated with the project were just and reasonable. *Id.* at 7. Further, if Peoples Gas had initially complied with 83 Ill. Adm. Code 590, it would not have incurred these costs. Sections 191.1, 191.3, 191.5, 191.7, 191.9, 191.11, 191.13, 191.15, 191.17, 191.23, 192, 193 and 199 are the minimum standards for transportation of gas and gas pipeline facilities. According to Staff, if a gas utility's distribution facilities do not comply with the Title 49 CFR that the Commission has adopted, then a violation of both federal and Commission rules exists. Staff Ex. 6.0 at 9. Staff notes that the Commission came to a similar conclusion in Docket No. 07-0585/0586/0587/0588/0589/0590 Cons. in which the Commission refused to pass costs on to ratepayers when the companies in that proceeding failed to comply with certain National Electrical Safety Code rules adopted in the Commission's rules. *Id.* at 10.

Peoples Gas argues that although an industry-recognized expert concluded the fittings were safe, the reasonable course of action was to replace them at the time that it did for convenience purposes, regardless of the fact that it could have sought a special permit to allow the pipefittings to remain in service. PGL Ex. 28.0 at 12. As Staff witness Darin Burk testified, Peoples Gas' ability to seek a special permit is in doubt because it would have been required to seek the special permit and demonstrate that safety will not be compromised prior to installing the non-approved material or component, as required by 49 CFR Section 193.341(b) of the PHMSA Guidance for State Programs. Staff Ex. 19.0 at 5-6; Staff Ex. 19.0, Attachment 3. Mr. Burk contends that PHMSA would not have granted a special permit.

Staff disagrees with Peoples Gas' argument that Mr. Burk incorrectly relies on subsection 190.341(b) which requires that the operator submit the application for the special permit at least 120 days prior to the effective date of the granting of the special permit, and that in the past, PHMSA has granted special permits after non-compliant equipment was installed. NS-PGL Ex. 44.0 at 6-7. The issue is that the pipes were unmarked as required by Section 192.63. Staff Ex. 19.0 at 6. Peoples Gas admits the pipes were not properly marked and were installed without obtaining a special permit. NS-PGL Ex. 44.0 at 7. For these reasons, Staff argues the installation of the fittings was not just and reasonable and the costs to replace the fittings should not be absorbed by the customers.

CUB-City

CUB-City recommend that the Commission adopt the recommendation of Staff witness Mr. Seagle to exclude all O&M expenses associated with the PPRP for the 2013 test year. Staff Ex. 16.0 at 7. Peoples Gas used plastic fittings that did not comply with industry standards in 49 CFR 192.63, and the PPRP is a remediation project to replace those non-compliant fittings. Staff Ex. 6.0 at 6. CUB-City aver that

Peoples Gas failed to demonstrate that the costs associated with the project were just and reasonable. Moreover, if Peoples Gas had initially complied with the Commission's Rules, it would not have incurred these costs. Staff Ex. 16.0 at 7. Staff witness Mr. Burk concluded that customers should not bear recovery of costs associated with the utility's failure to timely comply with Commission Rules. Staff Ex. 19.0 at 6. CUB-City maintain the Commission should not burden ratepayers with these expenses, which would not have been necessary had Peoples Gas complied with the Commission's Rules.

Commission Analysis and Conclusion

The Commission agrees with Staff and CUB-City that the costs of Peoples Gas' PPRP should be disallowed. The record does not support Peoples Gas' argument that these costs are just and reasonable. Peoples Gas has argued that an industry recognized expert concluded that the fittings were safe and that PHMSA has granted applications for special permits after non-compliant work has been installed. Moreover, Peoples Gas' only cited reason for deciding to replace the fittings at this time is its ability to coordinate this project with other scheduled work. If these facts, which Staff disputes, are in fact true, it appears Peoples Gas could have sought a special permit to allow the pipefittngs to remain in service instead of implementing this remediation project. The Commission finds that there is no basis for shifting the costs of replacing the non-compliant pipefittings to ratepayers. Accordingly, the Commission adopts Staff's proposed adjustment.

b. Legacy Sewer Lateral Cross Bore Program

Utilities

The Utilities explain that a cross bore is when a gas facility that has been installed using trenchless technologies intersects with an existing sewer main or sewer lateral. NS-PGL Ex. 20.0 at 5-6. The Utilities further explain that in the 1990's gas utilities began to use horizontal directional drilling ("HDD") to install natural gas pipes underground. *Id.* The utilities may have come in contact with sewer lines without any knowledge of such contact because many vintage sewer lines are made of clay and contain no tracer wire which makes it impossible to locate them with above ground locating devices. *Id.* This contact with the sewer lines can potentially cause a blockage in the sewer line. Peoples Gas states that its proposed legacy sewer lateral cross bore program ("Cross Bore Program") will proactively investigate those mains and service lines installed using HDD to determine whether there is a cross bore. *Id.*

The Utilities argue that Staff's proposed adjustment to remove the costs associated with the Cross Bore Program from O&M expenses should be rejected. The Utilities state that Staff's claims that the Utilities' procedures were inadequate or not followed are unsubstantiated. The procedures in place for the use of HDD are well developed and are consistent with industry standards and with the Gas Pipeline Technology Committee ("GPTC") guidelines. NS-PGL Ex. 44.0 at 4-5. Additionally, the Utilities procedures focus on safety, with specific emphasis on not striking underground

utilities. *Id.* Furthermore, the Utilities provide crews detailed training, supervise crews in the field, and conduct regular safety inspections. *Id.* However, the Utilities explain that despite best efforts, cross bores occur as acknowledged by the GTPC guidelines. *Id.* This becomes especially difficult with a complex sewer system like in the City of Chicago. *Id.*

Finally, the Utilities argue that the AG's argument that there has not been sufficient detailed planning for the project must also be rejected. The Cross Bore Program is a test year project that has not yet commenced. NS-PGL Ex. 44.0 at 4-5. However, the Utilities have been investigating cross bores as part of AMRP projects. *Id.* Thus, contractors are already out in the field as part of inspecting AMRP projects, and permanent assignments to the Cross Bore Program will be made when it begins in 2013. *Id.* Therefore, the Utilities conclude that there is sufficient planning in place to support the inclusion of program costs in operating expenses.

Staff

Staff explains that the Cross Bore Program is a remediation project involving locating existing cross bores in the system and, if one exists, rerouting the plastic main or service below, above or around the existing sewer facilities. Staff Ex. 6.0 at 12. Staff recommends that Peoples Gas' O&M expenses be adjusted by $5,700,000 to exclude costs for the Cross Bore Program. Staff Ex. 16.0 at 1. Staff recommends a similar adjustment of $2,600,000 for North Shore. *Id.* Staff argues that the Utilities did not demonstrate that the costs associated with this program were prudent and reasonable. Staff Ex. 6.0 at 12-13.

Staff witness Darin Burk disagrees with Peoples Gas' characterization that "cross bores are a circumstance beyond the Utilities' control." Staff Ex. 19.0 at 4, quoting NS-PGL Ex. 28.0 at 7. 49 CFR Section 192.605 requires operators of natural gas pipelines to develop manuals of procedures for conducting operations and maintenance activities and for emergency response. Such procedures are to be in place prior to conducting operation and maintenance functions. Pipeline replacement is considered an operation and maintenance function according to PHMSA. A prudent operator must have procedures that allow for the positive identification of the location of all underground utilities and substructures when directional drilling or boring is to be used for the installation of gas pipelines. Even when the approximate location of an underground facility has been identified and marked, the depth of the facility must be confirmed to avoid contact during the directional drilling process. The procedures must include methods to confirm that spatial separation of utilities has been maintained. According to a PHMSA Advisory Bulletin issued in 1999, operators must review their procedures to identify hazards associated with directional drilling. Staff Ex. 19.0 at 4-5; Staff Ex. 19.0, Attachment 1. Mr. Burk points out that Peoples Gas must also follow industry guidance as laid out in the GPTC guidelines. Staff Ex. 19.0, Attachment 2.

Mr. Burk opines that the fact that Peoples Gas has identified other locations where gas pipelines have been bored through sewers (NS-PGL Ex. 28.0 Rev. at 6-7)

establishes that the company's procedures were either inadequate or were not followed. Staff Ex. 19.0 at 5.

Staff argues that Mr. Hoops' reasoning behind his statement that because Peoples Gas provides detailed training to its employees and "has learned and continues to learn about the complexity of the City of Chicago's underground sewer system", the costs related to the Cross Bore Program are prudent and reasonable is flawed. NS-PGL Ex. 44.0 at 4-5. What Peoples Gas may or may not have learned about cross-boring since the date it initially discovered its errors is irrelevant and does not show that the Utilities management acted prudently in developing the Utilities' rules and regulations related to cross bores, or that those rules and regulations were adequate for the respective territories, especially the City of Chicago with its complicated system of pipes (Staff Ex. 19.0 at 4-5); nor, does it prove that the costs expended under the program are prudent and reasonable. Staff maintains that the Commission should accept Staff's proposed adjustments and exclude the costs from rate base because the Utilities cannot demonstrate that the costs associated with this program were prudent and reasonable.

AG

The AG recommends rejecting the estimated new expenses related to the Cross Bore Program based upon the Utilities' failure to meet their burden of justifying the expenses. AG Ex. 1.0 at 47. Two issues are particularly troubling to the AG. First, work has not even begun on the program, even though the concerns associated with potential cross-bore risks have existed for many years. Second, the timing of the proposed new investigation program and the associated expenses are overly discretionary and there is no evidence of a commitment to actually spend at forecasted levels.

The AG asserts that the Utilities provided little explanation of assumptions, calculations, or other support for the expenses on the Cross Bore Program in their direct case. According to the AG, as this docket progressed, the Utilities routinely and continually failed to satisfactorily justify these additions to O&M expenses. While this alone demonstrates the Utilities' lack of commitment to completing (or even starting) this project, the record evidence speaks volumes about the project. The Utilities assert that Peoples Gas has been "investigating" cross-bores as part of the AMRP program and that the project should begin in the first quarter of 2013. NS-PGL Ex. 44.0 at 5. However, the record evidence in this case demonstrates that, as of February 2013, only one out of eight positions alleged by the Utilities to be necessary to completing the Cross Bore Program have been filled. AG Ex. 4.0 at 50, AG Cross Ex. 12. Even more distressing to the AG is that, as of the date of the evidentiary hearing in this docket, the Utilities had not issued requests for bids. Tr. at 375-6. Forecasts were created without the benefit of having a bid or work plan in hand, further demonstrating the speculative nature of the potential addition to O&M expenses according to the AG. AG Cross Ex. 11.

The AG argues that the Commission should require the Utilities to provide more specific work plans that will detail the hiring of employees, contractual commitments to perform work, and detailed expenses for the Cross Bore Program. Until this level of detail can be provided, the Commission should reject the highly speculative additions to expenses. It is the AG's view that it is unclear at this point whether the Utilities are serious about starting or completing this project in a timely manner or whether activities and costs in other parts of the business could be shifted to cover cross bore investigation and remediation work without adding additional amounts to projected test year expense estimates. The AG maintains that the ratepayers of Illinois should not be on the hook for the expenses associated with such a speculative project with an unclear starting or ending date.

CUB-City

CUB-City recommend that the Commission adopt Staff witness Mr. Seagle's recommendation to remove all of the Utilities' expenses associated with the Cross Bore Program. CUB-City aver that the Utilities added these costs in their supplemental direct testimony, nineteen business days before the filing due date for Staff and Intervenor direct testimony, without adequate support for their calculations or rationale for why customers should pay for remediation of facilities Peoples Gas personnel improperly installed initially. *Id*. at 13-14. CUB-City note that while the Utilities claim that "standard industry practices and procedure may not have prevented all cross bores," and that cross bore situations were beyond their control (NS-PGL Ex. 28 at 7), Staff witness Burk found that the Utilities' procedures for avoiding cross bore situations were either inadequate or were not followed. CUB-City point out that Mr. Burk concluded, therefore, that the Utilities should bear the responsibility and burden of all costs associated with the Cross Bore Program. Staff Ex. 19.0 at 5. Accordingly, CUB-City recommend that the Commission make the adjustment supported by Mr. Seagle and Mr. Burk and remove all Cross Bore Program costs from the Utilities' revenue requirements.

Commission Analysis and Conclusion

The Commission believes the Cross Bore Program will be beneficial to the Utilities' ratepayers and the record shows that the Utilities' have taken appropriate measures when installing their pipes underground to prevent cross bores. The Commission agrees with the Utilities that given the size and complexity of the sewer system in the City of Chicago and the Utilities' pipe system, it is inevitable that some cross bores would exist. The Utilities have explained that the program has been planned based on the Utilities' experience from inspecting AMRP projects. They have been investigating cross bores as part of the AMRP projects and they have already had contractors out in the field as part of inspecting AMRP projects and the Utilities plan to make permanent assignments to the Cross Bore Program when it begins in 2013. Accordingly, the Commission finds that the Utilities have provided sufficient program planning and the costs should not be disallowed as proposed by Staff and the AG.

c. New Chicago Department of Transportation Regulations

Utilities

Peoples Gas proposes to include $13,900,000 in operating expenses in response to new regulations for Openings, Construction and Repair in the Public Way issued by the CDOT in July 2012. NS-PGL Ex. 20.0 at 1. The Utilities contend that the AG's and CUB-City's argument that costs related to the new regulations should be based on the Peoples Gas' experience in the fourth quarter of 2012 is without merit. Their position does not reflect the 2013 expense level. Peoples Gas' cost of service has significantly increased in response to the new regulations issued by CDOT. The Utilities note that while a number of initial fees applied in 2012, a significant majority of these expenses begin in January 2013. NS-PGL Ex. 44.0 at 8. Moreover, the Utilities state that Peoples Gas is able to accurately estimate the costs associated with the new CDOT regulations, as these costs are within the utility's control. *Id*.

Staff

Staff witness Seagle testified in his direct testimony that he could not determine the just and reasonableness of Peoples Gas' proposal to include O&M expenses for compliance with new CDOT regulations because Peoples Gas did not propose these expenses until it filed supplemental direct testimony which did not provide Staff with sufficient time to investigate Peoples Gas' proposal. Staff Ex. 6.0 at 15. As a result, Mr. Seagle requested that Peoples Gas provide additional information to support these proposed expenses. Based on the additional information that Peoples Gas provided, Mr. Seagle later testified in subsequent testimony that he was satisfied that the calculation of costs associated with the new CDOT regulations was just and reasonable, and therefore, withdrew his objections to Peoples Gas' proposal. Staff Ex. 16.0 at 6.

AG

The AG urges the Commission to reduce the O&M expenses proposed by Peoples Gas related to new CDOT regulations by $10,450,000. The AG argues that Peoples Gas' projection is not only overstated, it is unreliable and unsupported and would include in revenue requirement amounts that are in no way "known and measurable".

The AG posits that Peoples Gas has completely failed to meet its burden of justifying the majority of its requested expense. Peoples Gas' testimony on the topic has been limited at best. Peoples Gas, in its supplemental direct case, provided no workpapers or supporting documentation – merely perfunctory descriptions of the total amount sought to be recovered. AG Ex. 1.0 at 46-7. On rebuttal, the testimony of Peoples Gas witness Mr. Hoops on this subject did not even reach a page in length. NS-PGL Ex. 28.0 at 8. Mr. Hoops merely asserted that the costs were prudent and reasonable, but provided no analysis to support the claim. Instead, Peoples Gas papered the record with invoices and bids from what appear to be subcontractors performing repairs or other construction work on main replacement or segments. NS-

PGL Ex. 28.1. The AG argues that this "papering" of the docket includes copies of materials provided in response to AG and CUB discovery that actually shows considerable uncertainty in how the new regulations are to be implemented, as discussed in correspondence between Peoples Gas and the City of Chicago, and only $168,510 of actual incurred costs in July, August, September and October of 2012 under the new regulations, while providing nothing to justify the entire amount of expenses sought by Peoples Gas.

The AG maintains that at the root of the its proposed adjustment is a need to eliminate the uncertainty and gross speculation in Peoples Gas' incremental expense forecast related to new CDOT regulations. The AG notes that in a letter to the Chicago Department of Transportation included in its response to AG Data Request 16.25 (attach 02), the utility states that "Peoples Gas is struggling with understanding certain changes and also needs time to make procedural changes to implement certain revisions." AG Ex. 4.6 corrected. The AG argues this correspondence is an admission by Peoples Gas that its proposed adjustment is not "known and measurable" since the changes being imposed by the City of Chicago are not yet even fully understood by the utility.

The AG asserts that since Peoples Gas has been operating under the new regulations for more than six months, there is no need to charge ratepayers for speculative and overstated cost estimates for compliance when recent actual expenditures are available to quantify the needed adjustment to the revenue requirement. The AG's proposed adjustment for CDOT compliance expense accounts for actual costs experienced by Peoples Gas in the fourth quarter of 2012 during which the new regulations were fully effective. AG 4.0 at 46-7; AG Ex. 4.1. AG witness Mr. Brosch reviewed the actual costs for compliance and created an adjustment rooted in Peoples Gas' own historical experience. The AG argues the large difference between Peoples Gas' proposed recovery from ratepayers and its actual expenses is staggering. According to the AG, its proposed adjustment merely attempts to substitute truly "known and measurable" revisions to test year O&M expenses and charge to the ratepayers only what they owe.

The AG argues that Peoples Gas' own actions proposed in correspondence with the City of Chicago suggest that it is seeking to moderate the impacts of CDOT compliance upon the expenses that are incurred. Specifically, Peoples Gas has proposed a grace period during which it could negotiate with contractors and, presumably, reduce compliance costs. AG Ex. 4.6 corrected. Additionally, Peoples Gas acknowledged in its response to AG data request 16.25 that it "expects to be in full compliance with all new regulations by January 1, 2013" and that "all methods and timing of CDOT regulation changes have been implemented and approved" except for trench backfill material. AG Ex. 4.6 corrected. It is the AG's view that these statements belie the Peoples Gas' protestations that its costs will continue to escalate throughout 2013 or that its overstated estimates of CDOT compliance costs are "known and measurable".

It is the AG's position that the Commission should adopt its proposed adjustment because it is reasonable, necessary and reflective of the only known and measurable costs for compliance with CDOT regulations that is in the record.

CUB-City

CUB-City maintain that the estimates that Peoples Gas provided for its expense of complying with CDOT regulations is inadequately supported and likely grossly over-estimated, based on Peoples Gas' previous over-estimations of such expenses. CUB-City Ex. 2.0 at 52. CUB-City note that the Utilities did not identify these extraordinary expenses in their direct filing, but included the request in supplemental direct testimony filed in November 2012, even though the new CDOT regulations became effective in July 2012. *Id*. at 51. CUB-City witness Smith recommends an adjustment to reflect a more reasonable estimate of 2013 CDOT-related expenses.

CUB-City witness Smith found that from July through December 2012, Peoples Gas' total of such compliance expenses was $1,021,163, and the average monthly expense October through December 2012 was $289,858 per month. *Id*. at 51. That is far less than Peoples Gas' 2013 monthly forecasts. *Id*. at 52. One explanation suggested by Peoples Gas is that the CDOT regulations may be implemented differently than it originally assumed. CUB-City Ex. 1.0 at 52. CUB-City aver that Peoples Gas is seeking clarifications from CDOT concerning many aspects of implementing the new CDOT regulations, and those inquiries suggest such differences between Peoples Gas' asserted expectations and actual CDOT implementation are possible. *Id*. at 51-52. However, the dramatically increased amounts proposed are speculative, lacking an empirical basis and based on pure supposition (that past implementation of the CDOT regulations will change), in CUB-City's view.

CUB-City argue that Peoples Gas' actual compliance expenses for the most recent known quarter, October through December 2012, should be used as the most reliable basis for estimating the 2013 charges. *Id*. at 52. Mr. Smith therefore used that quarter to compute an annualized allowance for the impact on O&M Expense resulting from the new CDOT regulations. *Id*. at 52-53. While Peoples Gas estimates an allowance of $13,932,372 for 2013 CDOT charges, using its most recent actual experience of $289,858 per month, the 2013 allowance should actually be $3,478,000 ($289,858 x 12, rounded). *Id*. at 53. CUB-City aver that the extraordinary level of these expenses deserves much higher scrutiny than the Peoples Gas' speculative estimates permit, considering they do not reflect recent actual experience. Furthermore, CUB-City note the requested costs do not appear to reflect any further input from CDOT concerning how to interpret the new regulations; those responses may ultimately make compliance less costly than estimated by Peoples Gas. CUB-City maintain Peoples Gas did not provide substantial evidence to support a claim that the volume of work will increase at the dramatic rate its current estimates suggest. Consequently, CUB-City recommend that Peoples Gas' estimates be rejected as speculative, and that the most recent actual information be used as the basis for the ratemaking allowance.

Commission Analysis and Conclusion

The Commission finds that the Utilities' proposed O&M expenses related to compliance with new CDOT regulations are reasonable, supported by the evidence, and should be adopted. The evidence does not support the arguments by the AG and CUB-City that these expenses are speculative. The Utilities projected the costs for 2013 based on historical data and future construction projects. The Utilities have provided sufficient documentation detailing their projected expenses. Additionally, the testimony of Utilities witness Hoops and the Utilities' responses to Staff, the AG, and CUB-City data requests provide additional support for the inclusion of these expenses. It is also clear from the record that the majority of the expenses will be incurred in the beginning of the first quarter of 2013 and that it is therefore appropriate to adjust the 2013 operating expenses to reflect these anticipated costs. The Commission declines to adopt the adjustments recommended by the AG and CUB-City, as Peoples Gas' costs in the fourth quarter of 2012 do not accurately reflect the impact of the new CDOT regulations.

6. Productivity Adjustment

Utilities

The Utilities maintain that they have provided sufficiently detailed evidence supporting their proposed revenue requirements, and the AG's "productivity" adjustment should be rejected. The Utilities are entitled, as a matter of law, to just and reasonable rates that allow them the opportunity to recover fully their prudent and reasonable costs of service, and have provided extensive, detailed direct cases supporting their proposed revenue requirements. The Utilities also provided evidence presenting more than a *prima facie* case that their proposed rates are just and reasonable, which means that the burden of going forward with the evidence shifted to other parties to show that costs are unreasonable because of inefficiency or bad faith. NS-PGL Init. Br. at 94-95. The proposed revenue requirements are based on 2013 budgets and forecasts which were developed by subject matter experts, examined by independent CPA Deloitte & Touche LLP (per 83 Ill. Adm. Code § 285.7010), and have been carefully modified by ratemaking adjustments, revisions, and updates. PGL Ex. 5.0 Rev. at 4-9; NS Ex. 5.0 Rev. at 4-9; NS-PGL Ex. 25.0 at 6.

According to the Utilities, the AG claims that the Utilities' non-fuel O&M expenses should be reduced by .5% for each year, but has failed to provide any support for this argument and has failed to show any inefficiency that would necessitate this reduction on the part of the Utilities. *See* AG Ex. 1.0 at 24-25. The AG relies upon testimony cited in a San Diego Gas & Electric Company ("SDG&E") rate case before the California Public Utilities Commission ("CPUC") that discusses the average trend in productivity for gas utilities from 1999-2008 and from 2004-20087. AG Ex. 1.0 at 24. This rate case is inapposite, as it proposed a mechanism through which SDG&E's revenue requirement would be adjusted each year to reflect increases in certain expenses; moreover, the rate case excluded certain expenses from its analysis and failed to quantify separate or utility-specific productivity rates that would identify changes in

productivity at the Utilities. NS-PGL Cross Ex. 4. The Utilities argues this information failed to identify any inefficient operations at North Shore or Peoples Gas, and failed to present any information that supports a "productivity" adjustment. NS-PGL Init. Br. at 96-97.

Additionally, the Utilities note that the AG relied upon a New York Public Service Commission ("NYPSC") "Order Establishing Rate Plan" issued in NYPSC case 09-E-0588; this Order involved a settlement of both gas and electric rates, involved multi-year rate increases, and contained a "productivity" adjustment based on a prior regulatory "austerity" order. NS-PGL Init. Br. at 97. Similarly, the AG referred to rates approved by the Hawaii Public Service Commission ("HPSC") for Hawaiian electric companies; electric utilities with multi-year rate increase mechanisms which are irrelevant to the case at hand. *Id*.

The Utilities assert that the AG's productivity adjustment is further undermined by the fact that the AG is unable to rely upon any decision of the Commission, or any other public utility commission, that supports the imposition of an operating expense reduction based on the above-stated rationale. Instead, the AG has only relied upon adjustments made by utilities that are permitted to make multi-year rate increases. The AG is unable to cite any factual or legal basis for applying a productivity adjustment to the Utilities' final revenue requirements.

The Utilities argue that contrary to the AG's claims, the Utilities have provided ample evidence of and supported the methodology by which their budgets and forecasts were prepared. PGL Ex. 5.0 Rev. at 4-9; NS Ex. 5.0 Rev. at 4-9. Conversely, the AG is required to present specific facts relating to the Utilities' inefficiencies or missed opportunities for improvements in efficiency; the Commission has ruled that it will not consider a productivity adjustment without such specificity. *Illinois Bell Telephone Co.*, ICC Docket No. 02-0864, 2004 Ill. PUC Lexis 339 at *715 (Order June 9, 2004).

The Utilities point out that the AG, CUB-City, and Staff examined the Utilities' operating expenses and proposed specific adjustments. Yet, having reviewed all of the expenses as individual items, the AG proposal then makes a further proposed "productivity" adjustment on top of each of the applicable items. For example, the AG proposed specific adjustments to the IBS costs that make up a large portion of the Utilities' operating expenses, and yet, when the AG calculates its "productivity" adjustment, instead of removing IBS costs because they already have been analyzed, the AG applies that adjustment to the remaining IBS costs. AG Ex. 4.1, Sched. C-4; AG Ex. 4.2, Sched. C-4. The AG believes the specific reviews make the additional layer of "productivity" adjustments improper.

Staff

Staff states that it agrees with the Utilities' argument that Mr. Brosch has not provided sufficient support for the AG's proposed productivity adjustment. Therefore, Staff recommends that the Commission decline to adopt the AG's proposed productivity adjustment. Staff Ex. 13.0 at 23.

AG

The AG proposes a 1/2% per year productivity offset to reduce the Utilities' 2012 and 2013 test year non-fuel O&M expenses. The AG asserts this offset is necessary to counter unreasonable and unrealistic inflation assumptions made by the Utilities in forecasting their test year O&M expenses. The AG submits that the Commission should not blindly accept inflation and wage rate assumptions in forecasting test year expenses, but should instead insist upon some assumed improvements in operational efficiency or productivity, particularly when the regulated utility is insisting upon recovery of incentive compensation expenses that are claimed to generate such productivity benefits. The net effect of the AG's proposal reduces the Utilities' forecasted test year expenses, by approximately $2,490,000 in the case of Peoples Gas and $394,000 in the case of North Shore in the test period. AG Ex. 4.1, Sched. C-4; AG Ex. 4.2, Sched. C-4.

The AG notes that its productivity adjustment addresses only those costs that are within the control of management. It is reasonable to exclude certain expenses outside of management's control, such as costs for injuries and damages, insurance and postage, and pension and post-employment benefit costs. The AG states that its adjustment reasonably assumes that productivity gains can be achieved through proper management, an assumption directly supported by the Utilities' testimony. Utilities witness Ms. Cleary testified that an incentive metric exists in order to reduce operational costs. NS-PGL Ex. 9.0 at 5. Ms. Cleary further stated that the impetus behind the incentive metric was to reduce the amount of O&M expenses that ratepayers are responsible for. *Id.* at 4-5. Thus, the AG argues the Utilities are essentially anticipating productivity gains – as any responsible utility management would.

The AG states that the Utilities' argument that any productivity adjustment is unnecessary is inconsistent with their argument that the Utilities anticipate cost reduction efficiency gains. Moreover, the Utilities' explanations as to why any productivity offset is unnecessary or unreasonable should be seen as simply excuses which the Commission should disregard as meritless. The Utilities have failed to specifically identify and quantify what assumptions they undertook when making their own productivity gain assumptions. However, the AG argues its proposed adjustment, on the other hand, is supported by an examination from AG witness Mr. Brosch.

The AG states that Mr. Brosch closely examined the Utilities' budgeting assumptions presented in their Schedule G-5 and found that no stated productivity assumptions were made to offset the wage increase rates and annual inflation rates were applied without an offset for productivity efforts. AG Ex. 4.0 at 24-25. According to the AG, the main driver behind the Utilities' labor forecasts were, in fact, their unsupported judgments about the level of work expected to be performed in 2013 and their estimates about how many additional employees would be required to perform this work. As for non-labor expenses, the Utilities simply used broadly applied general inflation indexing for non-gas expenses. The AG argues these inflation-only judgments

do not provide sufficient reason to impose additional expenses onto the ratepayers without similar and offsetting judgments with regard to achievable productivity improvements.

The AG also argues that the Utilities are asking the Commission to blindly accept as fact that utility management has extrapolated historically and consistently achieved gains in productivity and "inherently" accounted for those gains with no documentation of any specific forecasted cost-savings stated or quantified in the record. The AG's proposed adjustment to assume modest incremental productivity improvement each year would allow the Commission to require some performance by management to achieve incremental productivity improvements that will serve to offset the effects of inflation and wage rate increases that were explicitly factored into test year expense forecasts.

The AG avers that increased workloads, as well, should not have an impact on the Utilities' ability to achieve greater efficiency and productivity. The AG notes that in response to AG Data Request 16.10, Utilities witness Ms. Gregor explicitly conceded that she "does not believe that productivity improvements cannot occur when workload is increasing." AG Ex. 4.4 at 5. The Utilities further agree that "management employees of public utilities like Peoples Gas and North Shore [should] be expected to strive to achieve improved productivity and cost reductions in their day-to-day actions to manage the business." Tr at 74. Therefore, the AG argues that the Commission should not give weight to the Utilities claims that changes in workload somehow excuse management for achieving productivity gains.

The AG states that the mere fact that turnover occurs does not lend credence to the Utilities' arguments against the productivity offset. Turnover is a routine part of business for the Utilities and one which the Utilities' management must be able to overcome and achieve gains over time. They acknowledge this very notion, in their responses to AG Data Request 16.11, in which Utilities witness Ms. Gregor acknowledges that turnover is not unique to the Utilities and also "did not conclude that firms that experience turnover of seasoned employees cannot achieve improved productivity." AG Ex. 4.4 at 8. With these acknowledgements in mind, the AG maintains that it becomes even more critical to note that none of the Utilities' witnesses have testified with certainty where any assumed productivity gains have actually been included in their forecasts. *See, generally,* AG Ex. 4.4.

Finally, the AG argues that the Utilities' criticism that its adjustment is "subjective" is equally without merit. The Utilities acknowledge that a number of forecasted expenses are, themselves, subjective, including, as noted in the Utilities' response to AG data request 16.13, "some of the elements of the Companies' rate case test year forecasts of O&M expenses or rate base." AG Ex. 4.4 at 14. When using a forecasted test year, where nearly all of the input amounts are based upon estimates, it is essential that judgment be applied. The AG maintains that its productivity adjustment is no less subjective than many of the assumptions relied upon by the Utilities in preparing their own test year forecasts.

The AG notes other state's commissions have implemented productivity offsets to address the reasonable expectation of the ratepayers. For example, the CPUC regularly requires offsets for expected productivity improvements. The NYPSC recently required a 1/2% annual productivity offset in a rate case and noted that such an adjustment was "consistent" with its policy. Additionally, the HPSC similarly applies an annual .76% productivity offset to O&M expenses.

The AG maintains that given the reasonableness of its proposed 1/2% adjustment to O&M, the inability of the Utilities' to refute the reasonableness of the adjustment, and the actions of sister state's commissions, the Commission should adopt the AG's proposed adjustment.

Commission Analysis and Conclusion

The Commission agrees with Staff and the Utilities and concludes that AG witness Brosch failed to provide convincing legal or factual support for his proposed adjustment. Mr. Brosch's proposal does not point out any specific inefficiencies or missed opportunity for improvements in inefficiency. Moreover, the AG's references to cases in other jurisdictions involving this type of an adjustment are unpersuasive, for many reasons, including the fact that the cases cited are not analogous to the facts in this proceeding. Unlike this proceeding, those cases relate to utilities that are allowed multi-year rate increases. Thus, the Commission declines to adopt Mr. Brosch's proposal.

7. Administrative & General

a. Adjustments to Integrys Business Support Costs

Utilities

The Utilities argue that they have provided sufficient evidence through testimony and supporting exhibits that support the costs and expenses attributable to IBS. In direct testimony, the Utilities showed portions of their final revenue requirements that are based on costs allocated or charged to them from IBS, including budgeted and forecasted transactions with affiliated interests for 2012 and 2013. PGL Ex. 5.0 Rev. at 18-19; PGL Ex. 5.1, Sched. C-12 at 1-2; NS Ex. 5.0 Rev. at 15-16; NS Ex. 5.1, Sched. C-12 at 1. The Utilities assert that Staff's argument that the Utilities have failed to support increases in IBS costs, ignores the testimony and data provided by Utilities' witnesses that fully explain the IBS benefits costs and their causes.

The Utilities challenge Staff's initial proposed adjustment for several reasons. First, the Utilities argue that Staff's proposal to disallow $5,353,000 of benefits expenses and $3,018,000 of injuries and damages expenses is flawed because the benefits expense was fully supported in detail and it was not refuted by any witness. PGL Ex. 11.0; NS Ex. 11.0; NS-PGL Ex. 31.0; NS-PGL Ex. 25.0; NS-PGL Ex. 25.1P. Second, Staff's argument that the injuries and damages expenses are erroneous must also be rejected, as Staff has failed to account for shifts in management and varying

sources of expense payment from the 2008-2013 period that fully explain the increase. NS-PGL Ex. 25.0 at 3-4; NS-PGL Exs. 25.1P, 25.2P. Third, in calculating the injuries and damages expenses, Staff overstated the proposed adjustment by another $1,022,000. NS-PGL Ex. 25.0 at 3-4.

The Utilities contend that Staff's reformulated proposal presented in rebuttal testimony to disallow even more, $12,327,000, is also mistaken. The Utilities argue that Staff's new proposal continued to disregard evidence provided by the Utilities' witnesses explaining and supporting higher benefits costs and their causes. Staff's rebuttal testimony also failed to resolve the faulty injuries and damages expenses calculation by accounting for the amounts paid directly by Peoples Gas, and continued to overstate the proposed adjustment to IBS expenses. Staff's rebuttal also failed to factor in certain other IBS costs. NS-PGL Ex. 41.0 Rev. at 3-4; NS-PGL Ex. 41.1P. The Utilities maintain that Staff's errors, together, entirely eliminate the adjustment, and, when corrected, actually would support an increase. NS-PGL Init. Br. at 102-103. Moreover, Staff's speculation that there may have been intercompany charges that declined sufficiently to offset expense increases (Staff Init. Br. at 58) is unsupported and, in fact, directly contradicted by the evidence. That speculation does not present a lawful basis for a disallowance according to the Utilities. *Ameropan Oil Cor. v. ICC,* 298 Ill. App. 3d 341, 348, 698 N.E.2d 582, 587 (1st Dist. 1998).

The Utilities maintain that Staff's new argument in its Initial Brief that the AG's analysis of IBS costs somehow validates Staff's proposed adjustment (Staff Init. Br. at 59-60) is also flawed. The Utilities explain that of the $12,166,000 of AG-proposed adjustments that Staff cites for comparison, only $2,085,000 are direct adjustments to the IBS costs allocated and charged to Peoples Gas, with another $40,000 being a placeholder change in the rate of return on IBS plant investments. *See* Staff Init. Br. at 60. The other $10,081,000 of AG proposed adjustments that Staff cites here is the aggregate amount of AG proposed adjustments to (1) overall employee headcounts of both of the Utilities including both utility employees and some IBS employees attributed to the Utilities and (2) overall operating expenses (except for certain categories) of both of the Utilities including non-IBS costs and IBS costs, and thus they include non-IBS costs as well as IBS costs and they include amounts for North Shore as well as Peoples Gas. *See* Staff Init. Br. at 59-60. Thus, the Utilities assert the notion that the other $10,081,000 of AG-proposed adjustments somehow validates Staff's proposed IBS cost adjustments is illogical. In fact, the AG's final proposed adjustments to IBS costs of $2,085,000 reflects the AG's analysis of all eight IBS cost "home centers" and IBS plant investment costs, with the AG's revising its direct testimony proposal and in rebuttal proposing adjustments to only two of the cost home centers and depreciation expense. NS-PGL Init. Br. at 104-106. Therefore, the Utilities conclude that if anything, the AG's analysis refutes Staff's proposal. For these reasons, the Utilities contend that Staff's proposed adjustments must be rejected by the Commission.

The Utilities state that the AG proposed incorrect adjustments to two IBS home centers in rebuttal testimony. The AG also proposed adjustments to IBS depreciation costs which the Utilities agree with in theory, but argue have been incorrectly calculated.

The Utilities found that, in direct testimony, the AG identified two minor adjustments that were warranted; the Utilities made these adjustments in rebuttal testimony. The Utilities contend that they have provided evidence that the rest of the IBS home center costs are fully supported, and that any variances in the IBS Corporate Controller home center costs are due to increased outside services related to convergence standards and International Financial Reporting Standards ("IFRS"). NS-PGL Ex. 41.0 Rev. at 6; NS-PGL Ex. 41.5. Similarly, the Utilities have provided evidence that, based on 2010-2012 average costs and inflation, the IBS legal home center costs were not overstated. NS-PGL Ex. 41.0 Rev. at 6; NS-PGL Ex. 41.6. The Utilities state that the AG's analysis is specious because it did not use full year data and failed to include a factor for inflation. AG Ex. 4.1, Sched. C 8, line 3 and fn. (c); AG Ex. 4.2, Sched. C-8, line 3 and fn. (c).

The Utilities state that they agree that the adjustment to IBS depreciation that was proposed in the AG's rebuttal testimony is warranted, but clarify that the adjustment was miscalculated. The IBS costs should include seven months of depreciation, instead of the six months proposed by the AG. NS-PGL Exs. 41.4P, 41.4N. The Utilities state that they have already made these adjustments in their surrebuttal testimony, however, that the remainder of the AG adjustments must be rejected.

Staff

Staff witness Pearce proposed an adjustment to reduce intercompany charges from IBS to Peoples Gas in direct testimony. Staff Ex. 4.0 at 13 – 16; Sched. 4.02 P. Ms. Pearce later revised this adjustment in her rebuttal testimony. Staff Ex. 14.0 at 16 – 19; Sched. 14.02 P. Staff avers that the Commission should adopt its recommended adjustment because the Companies have failed to support the significantly higher level of test year intercompany charges, even after allowing for the overall inflation adjustment of 2.2% that was used by the Companies in their test year forecast. Staff maintains that this is demonstrated in Staff witness Pearce's comparison of test year IBS charges to the five-year average calculated in Staff's direct and rebuttal testimony. Staff Ex. 14.0, Sched. 14.02 P; Staff Ex. 4.0, Sched. 4.02 P.

In direct testimony, Staff witness Pearce performed an analysis of intercompany charges from IBS to Peoples Gas that compared monthly and annual costs over the five- year period 2008 through the first nine months of 2012, using actual cost data provided by the Company. She also reviewed the Company's response to Staff DR BAP- 2.06 (d), which provided explanations for fluctuations within individual cost categories over the four year period 2008 – 2011, based on actual costs. Based on this information, Ms. Pearce concluded that Peoples Gas supported only $7.621 million of its requested $15.744 million increase. Sched. 4.02 P at 1. She utilized a five-year average for the period 2008 – 2012 as the basis for this adjustment. For 2012, Ms. Pearce relied upon actual data for the first nine months, annualized to estimate the yearly total. That amount, along with actual charges for the previous four years (2008 – 2011) is reflected on Schedule 4.02 P, page 2. As the notes on page 2 indicate, this information was taken from annual reports submitted by the Company pursuant to Section 4.5 of the Master Affiliated Agreement approved in Docket No. 07-0361. Ms.

Pearce also verified that the cost information provided by the Company for the months of July 2011 through September 2012 agreed with monthly IBS invoices received by the Company. Staff argues that the Companies' witness Christine M. Gregor agreed the increases in IBS costs were not clearly explained by the Companies, but she declined to accept Staff's adjustment, claiming the amount of disallowed expense consists mainly of increases in benefit costs and injuries and damages expenses. NS-PGL Ex. 25.0.

In rebuttal testimony, Ms. Pearce revised this adjustment to include the actual charges for October and November 2012 in the annualized 2012 expense, and to apply the Company's overall inflation rate of 2.2% in lieu of recognizing increases in expenses for depreciation, rate case, and legal costs. Staff Ex. 14.0 at 16 – 19; Sched. 14.02 P at 1 – 3.

Staff contends that the Company has attempted to justify an unreasonably high level of intercompany charges in the future test year by selectively addressing increases in two areas of expense. Staff argues that given the magnitude and variety of costs that flow through the intercompany charges (from IBS to Peoples Gas), Ms. Gregor's explanation does not support the overall level of increase, 10.68%. Staff Ex. 14.02 P. For example, even if expenses increased in the areas of benefits costs and injuries and damages, other intercompany charges may have also declined that would offset the two increases selectively chosen by Ms. Gregor.

Staff maintains that an even larger adjustment than Staff proposed in rebuttal testimony would have been warranted if it would have addressed the Companies' critique to remove 2008 because excluding 2008 from the analysis would have resulted in a four-year average with an even greater disparity to the 2013 test year forecast. Specifically, the five-year average that Ms. Pearce calculated (Staff Ex. 14.0, Sched. 14.02 P at 2) produces an average annual total intercompany charge of $145,345,324 versus $141,349,998 for a four-year average without 2008. *Id.* at 3. Using the four-year average would result in an adjustment even greater than Staff recommended since the adjustment would be derived by taking the 2013 test year forecast for intercompany charges of $160,870,000 (*Id.* at 2) less the smaller four-year average annual total intercompany charge. Staff argues that given that the five-year average is less than three percent greater than the four-year average, the impact of 2008 does not seem to be significant to the estimate overall.

Accordingly, Staff urges the Commission to accept its adjustment to reduce intercompany charges from IBS to Peoples Gas. Staff contends this will cause intercompany charges to align more closely with the five-year average calculated by Staff, as adjusted by 2.2% for the overall rate of inflation utilized by the Utilities in the 2013 test year.

Finally, Staff observes that the AG also proposes an adjustment based on a different methodology than the one used by Staff. Staff states that while it does not endorse the AG's methodology, it notes that the AG's proposed adjustment is not significantly different in total dollar impact.

AG

The AG notes that the Companies have the burden of proving that their proposed test year level of expenses are just and reasonable pursuant to Section 9-201 of the Act. AG witness Mr. Brosch proposed downward adjustments in AG Exhibits 1.3 and 1.4 at Schedule C-8 to several categories of IBS billings to PGL and NS where significantly higher forecasted test year charges above historical levels were proposed, because such increased expenses had not been adequately explained in the Companies' filing and responses to AG data requests. He explained that the Companies provided no detailed supporting calculations for their proposed test year O&M expense forecasts for affiliate charges to PGL and NS as part of their filed direct testimony, exhibits and workpapers, so considerable effort was required by the AG to discover and evaluate the basis for such forecasts. AG Ex. 1.0 at 48-49. The AG points out that it revised or retained several of these initial adjustments in its rebuttal case based on the receipt of additional information from the Companies.

The AG maintains that the Companies failed to meet their burden of explaining and justifying the basis for such large, projected cost increases. AG Ex. 1.0 at 48-49. The inquiries the AG made related to IBS forecasted expenses chargeable to PGL and NS in the test year revealed very large projected IBS cost increases that were not consistent with recent actual spending levels at IBS, and could not be explained by either general wage increase adjustments or by escalation rates applied for inflation. For these unusual projected expense levels that are not consistent with historical actual spending, Mr. Brosch proposed elimination of the unexplained variances in such costs unless and until the Companies provide in their rebuttal evidence a complete and detailed justification for such projected large expense increases.

Mr. Brosch testified that the Companies' projected IBS test year expenses are much larger than historically incurred cost levels. He challenges the IBS line item forecasted expenses found in AG Ex. 1.11 with projected test year 2013 expenses (1) that greatly exceed the recorded "Actual" expenses in 2010, 2011 and in 2012, to date; (2) where the "Key Drivers" do not fully justify the "Unexplained Variance" in the response; and (3) where the total projected IBS departmental costs exceed historical cost levels by significant amounts. AG Ex. 1.0 at 50.

The single largest element of Mr. Brosch's adjustment challenging the Companies' IBS forecasted expenses relates to IBS Depreciation. Yet, the AG argues the only explanation of "Key Drivers" for this increase was the Companies' WAM, transaction based software and other net assets. Given the fact that proposed depreciation amounts far exceed the recorded expense levels in 2010, 2011 and 2012, to date, Mr. Brosch testified that considerably more detailed calculations and explanations should be produced to refine these estimates before they become part of the Companies' revenue requirements. *Id.*

The AG takes issue with Companies witness Gregor's statement that the Companies provided additional information explaining the forecasted expense increases in each of the IBS home centers and that these explanations show that all of the costs, other than the two minor adjustments made in response to the AG's adjustment, are reasonable. The AG acknowledges that the Companies did in fact make the "two minor adjustments". However, the AG states that with regard to the other IBS charges that it challenged, the Companies failed to provide any specific rebuttal testimony addressing the unexplained variances in these IBS home centers.

The AG states that while in some instances the additional information provided by the Companies was sufficient to fully explain the proposed cost increases from historical IBS costs, in other instances the additional information either supported a revised adjustment amount or retention of the AG's original proposed adjustment. Specifically, the AG notes that it eliminated its adjustment for information technology costs center A59 charges, Safety Health and Wellness home center A45 charges and IBS Utility Group Executive Office allocated charges based on additional information provided by the Companies.

The AG states that it also revised its recommended adjustment applicable to IBS home center A06 for Corporate Controller allocated costs and for IBS depreciation expense based on the additional information provided by the Companies. Mr. Brosch testified that he revised his recommended adjustment applicable to IBS home center A06 for Corporate Controller allocated costs after receiving an itemized breakdown by vendor of IBS Corporate Controller charges provided by the Companies. He explained that Corporate Controller IBS actual payments to vendors in 2011 totaled $3.3 million and in the 10 months ending October 31, 2012 totaled $2.6 million. However, in the forecasted test year, about $5.0 million of payments to vendors by IBS is forecasted. Mr. Brosch further testified that this comparison illustrates the apparent overstatement of total estimated vendor charges for services to the IBS Corporate Controller organization, prior to allocations among Integrys affiliates. Additionally, he notes that the itemization of IBS Corporate Controller forecasted 2013 expenses includes more than $1 million for IFRS consulting work in 2013 that is highly speculative, and $140,000 for potential acquisition and merger-related services that are also speculative and, as such, should not be charged to the regulated utilities in Illinois if actually incurred by IBS.

Mr. Brosch stated that he revised his IBS depreciation adjustment based on the information provided by the Companies in response to the AG's data request. He explained that IBS allocated charges to the Companies include depreciation and amortization expense for assets employed by IBS to provide services to its affiliated companies. He further explained that his analysis of IBS depreciation amounts forecasted for the 2013 test year indicated unreasonably large increases in projected amounts allocable to PGL and NS. The overall unexplained variance for such increases was the basis for Mr. Brosch's original adjustment for IBS depreciation expense. However, Mr. Brosch testified that a more specific adjustment than for IBS depreciation is needed based on the additional information provided by the Companies. This more

specific adjustment is to update depreciation charges for the updated in-service date expected to be achieved in June of 2013 for the GAP software development project to improve the WAM System, as more fully explained in the Companies' response to data request AG 12.20. AG Ex. 4.0 at 55-56.

Mr. Brosch clarified that the AG has not revised its proposed adjustment to reduce IBS legal charges to the Companies because the information provided by the Companies in response the AG's data request supports a conclusion that legal fees in total have been overstated in the 2013 forecast prepared for the IBS legal cost center. He testified that this overstatement can be observed in comparisons of forecasted 2013 amounts to recorded 2010, 2011 and year-to-date 2012 spending in the Companies' response to AG 12.08 and 12.19. AG Ex. 4.0 at 54-55. The AG notes that it requested a more detailed breakdown of recorded historical legal fees, forecasting assumptions and calculations supportive of test year IBS legal forecasted expenses to assist in the analysis of forecasted spending levels, but the Companies objected to providing additional breakdowns and did not provide any additional support for the proposed forecasted 2013 expense levels.

The AG asserts that these adjustments, as provided in their final format and based on the evidence in the record, as listed in AG Ex. 4.1 and 4.2, Scheds. C-8 and C-9, should be adopted by the Commission.

CUB-City

CUB-City recommend that the Commission adopt the adjustment of AG witness Mr. Brosch to remove certain costs that IBS has billed to NS/PGL. CUB-City support Mr. Brosch's statement that the Companies failed to meet their burden of explaining and justifying the basis for their very large projected cost increases. AG Ex. 1.0 at 48-49. CUB-City note that Mr. Brosch identified "unexplained variances," which were greater than the increases caused by general wage increases and for general inflation. *Id*. at 49. CUB-City therefore recommend that the Commission adopt the AG's proposed adjustments to remove IBS affiliate charges because the Companies did not meet their burden of proof and failed to establish that these charges were just and reasonable.

Commission Analysis and Conclusion

The Commission agrees with the AG and Staff that the Utilities have failed to meet their burden of explaining and justifying the basis for their projected test year O&M expenses for intercompany charges from IBS to Peoples Gas and North Shore. Based on a review of the record, the Commission finds that the AG's proposed adjustments are supported by the evidence, reasonable, and should be adopted. AG witness Brosch proposed specific adjustments to several categories of IBS billings to Peoples Gas and North Shore where the projected expenses varied significantly from historical levels. Mr. Brosch reasoned that these adjustments were necessary because the increased expenses had not been adequately explained by the Utilities. The Commission believes

the AG's proposed adjustments result in a more reasonable forecasted expense level that properly reflects the intercompany charges explained and supported by the Utilities.

b. Advertising Expense

Utilities

The Utilities note that in rebuttal and surrebuttal testimony, they accepted $69,000 of Staff's proposed adjustments to advertising expenses, but rejected the remaining proposed adjustments because the remaining challenged expenses were recoverable under Section 9-225 and also were charitable in nature. The Utilities' argue that Staff's proposed adjustments must be rejected, as they disallow expenses that were properly incurred in ways that benefit customers and the communities in the Utilities' service territories. Moreover, not only are Staff's adjustments entirely in error, but Staff's proposed adjustment to Peoples Gas is overstated by $10,000, as Staff failed to account for the fact that Peoples Gas removed an additional $10,000 of the challenged costs from its revenue requirement in the Utilities' surrebuttal. Staff Init. Br., App B at 3, col. (o); Staff Ex. 13.0, Sched. 13.03 P at 1; NS-PGL Ex. 42.0 Rev. at 13; NS-PGL Ex. 42.2P at 2, col. [D], reflected in NS-PGL Ex. 42.1P, col. [D], line 23.

The Utilities contend that the evidence shows that the costs in question are sponsorships that benefit customers and communities and are recoverable under Section 9-227, and Staff does not and cannot argue that Section 9-225 is an exception to recovery under Section 9-227. NS-PGL Ex. 26.0 at 7-8; NS-PGL Init. Br. at 107-108. Despite Staff's argument that the Utilities' failed to properly list these amounts as charitable contributions on their Schedule C-7's, prior Commission decisions have shown that the Utilities should be able to recover recoverable expenses even in the case that such expenses were recorded incorrectly, and to rule otherwise would be punitive with no justification. NS-PGL Ex. 42.0 at 5-6, 8-9; *Commonwealth Edison Co.,* ICC Docket No. 99-0117 (Order on Rehearing March 9, 2000); NS-PGL Init. Br. at 109. In addition, the Utilities argue that Staff contradicts itself. Staff elsewhere stated in its Initial Brief that "[w]hether the Companies record institutional events support costs as miscellaneous general operating expense or charitable contributions, should not dictate whether these particular miscellaneous general operating expenses should be recovered from ratepayers." Staff Init. Br. at 65.

The Utilities argue that they have provided sufficient support for the expenses in question to be recovered under Section 9-225 in any event, presenting documentation and other evidence that demonstrate that the expenses were incurred pursuant to the statutory requirements. NS-PGL Ex. 42.0 Rev. at 5-7; NS-PGL Ex. 42.3. In claiming that the Utilities cannot recover costs that paint them in a "philanthropic light," Staff attempts to disallow costs that are beyond the scope of Section 9-225 and promotes a reading of Section 9-225 that is wrong on its face and that is inconsistent with the express allowance of charitable costs recovery under Section 9-227. Moreover, Staff does not provide any actual evidence that the sponsorships are for "promotional advertising" or "goodwill or institutional advertising," in contravention of Section 9-225(1)(c)-(d). Staff also fails to acknowledge that the express language of Section 9-

225 provides that the Commission may approve such costs if "the Commission finds the advertising to be in the best interest of the Consumer…." According to the Utilities, they have provided overwhelming evidence that the challenged sponsorships benefit customers and communities within the Utilities' service territories. Staff also is inconsistent in its treatment of such expenses, having failed to propose adjustments to similar advertising expenses in previous cases. NS-PGL Init. Br. at 109-110.

The AG points out that Staff refers to four previous Commission orders disallowing advertising expenses of a promotional, goodwill, or institutional nature in support of its proposed adjustments. Staff Ex. 3.0 at 20. However, the Utilities' argue these orders discuss cases that are factually dissimilar to the current facts, and, with the exception of the *Ameren Illinois 2012* Order, fail to discuss the "philanthropic light" theory. The *Ameren Illinois 2012* Order apparently is the first order under which sponsorships were disallowed under the "philanthropic light" theory pursuant to Section 9-225, despite the fact that the review of advertising expenses has been a practice of both Staff and the Commission for decades. In any event, the *Ameren Illinois 2012* Order is legally and factually distinguishable because, as previously discussed, Section 9-225 does not apply to costs recoverable under Section 9-227, plus, there is no evidence that the sponsorships in question in the instant case are properly qualified as goodwill advertising. Lastly, the *Ameren Illinois 2012* Order fails to address the language of Section 9-225 that promotes advertising done in the best interests of the customers. Consequently, the Utilities state that here, as noted above, the sponsorships are in the best interests of customers.

Staff

Staff recommends that the Commission accept Staff's adjustments to remove advertising expenses that are of a promotional, goodwill or institutional nature, and are therefore barred from cost recovery under Section 9-225 of the Act. Staff Ex. 3.0 at 19; 220 ILCS 5/9-225. Staff explains that the Utilities agreed that certain advertising expenses could be considered promotional, goodwill, or institutional in nature. NS-PGL Ex. 26.0 at 6. However, the support for the Utilities' acceptance of disallowed advertising expenses is not clearly stated. It appears that the Utilities divided the 2011 sponsorships into two groups: sponsorships they identified as allowable and the remaining sponsorships as a part of Staff's disallowance. Staff Ex. 13.0 at 14 and Scheds. 13.03 N and P at 3. There is no readily apparent difference between the two groups to demonstrate why a sponsorship was or was not deemed allowable for recovery from ratepayers.

The Utilities argue that sponsorships should be recoverable from ratepayers because sponsorships: 1) support events and organizations that are valued by communities the Utilities serve; 2) enable the Utilities to provide information on energy education, online billing and energy assistance to event attendees; and 3) represent charitable contributions. NS-PGL Ex. 26.0 at 7. Staff asserts that these arguments are meritless for the following reasons.

First, the assertion that communities in the Utilities' service territories would value sponsorships of events and organizations has no bearing on whether the expense of such sponsorships should be recovered from ratepayers. The sponsorships put the Utilities' name before the public in a philanthropic light, and therefore, must be disallowed in compliance with Section 9-225 of the Act and prior Commission orders. Staff Ex. 13.0 at 15.

Second, the assertion that the sponsorships enable the Utilities to provide relevant information to event attendees has not been substantiated with the provision of advertising materials as required by Section 9-226 of the Act. 220 ILCS 5/9-226. The only support the Utilities provided was informational messaging concerning the Utilities' system and safety. NS-PGL Ex. 42.3. Based on the information provided by the Utilities to show that the requirements of Section 9-226 of the Act have been met, it is not possible to determine what advertising materials were provided, and for which sponsored event. The Utilities merely assert that the events' advertising materials contain information that would "allow for the Utilities to promote a number of initiatives including energy efficiency programs, safety and financial assistance directly to customers." The support to substantiate the Utilities' claim, as required by Section 9-226 of the Act, is not contained within the record of this proceeding. Staff Ex. 13.0 at 15-16. Therefore, Staff argues cost recovery must be denied.

Third, the assertion that event sponsorships are charitable contributions is not corroborated with the charitable contributions listed on the Utilities' Schedules C-7 as required by 83 Ill. Admin. Code 285. The Utilities filed their rate cases requesting that these costs be recovered as advertising costs. This Commission should not allow recovery of these advertising costs because the Utilities have decided in the middle of this proceeding that these costs are now charitable contributions. Staff Ex. 13.0 at 16. The Utilities contend that when a contribution is made to a charity by sponsoring an event, where information about energy efficiency and/or safety is provided, the expense should be allowable regardless of whether it is recorded as a charitable contribution or as an advertising expense. NS-PGL Ex. 42.0 at 8. However, recording an expense in the proper account does not mean that the Utilities' should be allowed to recover that expense – rather the standards for recoverability are set out in the Act. The Commission does not commit itself to the approval or acceptance of any item set out in any account, for the purpose of fixing rates or in determining other matters before the Commission. 83 Ill. Adm. Code 505.210. The fact that the expense of sponsorships could be recorded in certain accounts, does not guarantee that the Commission will allow such expenses in rates.

Staff argues that its recommendation to remove advertising expenses that are of a promotional, goodwill or institutional in nature are appropriate and should be adopted by the Commission. Staff notes that the Commission has previously disallowed goodwill advertising expenses from the Utilities' rates. Staff Ex. 3.0 at 20.

CUB-City

CUB-City recommend that the Commission adopt the adjustments of Staff witness Mr. Ostrander to remove advertising expenses that are of a promotional,

goodwill, or institutional nature. CUB-City argue these expenses are expressly prohibited by Section 9-225 of the Act. CUB-City aver that promotional costs such as employee apparel and company logoed pens, key chains, pencil pouches, etc., which the Utilities also continue to request recovery of, are also clearly prohibited by the Act. Staff Ex. 3.0 at 19.

Commission Analysis and Conclusion

Staff seeks to disallow the Utilities' sponsorships to: (1) in the case of North Shore, Arden Shore Child and Family Services, the City of North Shore Chicago, the College of Lake County, the Preservation Foundation, the Waukegan Park District, the Waukegan Public Library, and Window to the World Communication and (2) in the case of Peoples Gas, American Legion, the Chicago Humanities Festival, the Chicago Public Library, Chicago Sinfonietta, the Friends of the Parks, the Redmoon Theatre, and Window to the World Foundation. The Commission finds that the Utilities have established that the nature of these sponsorships is charitable and recoverable under Section 9-227. The Commission does not take the fact that the Utilities recorded these expenses incorrectly lightly and believes the Utilities must be more careful in distinguishing sponsorship and institutional expenditures that are allowable for charitable purposes and those that are allowable advertising expenses. The Commission notes that the rulemaking in Docket No. 12-0457 should provide guidance as well. However, the Commission believes the nature of the expense is more important and declines to adopt Staff's position that these expenses can not be considered as charitable contributions because the Utilities initially recorded them as advertising expenses. Moreover, the Commission notes that the recipients of these sponsorships are either charitable organizations or organizations providing public welfare or educational services in the Utilities' service territory. Accordingly, the Commission declines to adopt Staff's adjustment.

c. Charitable Contributions

Utilities

Peoples Gas seeks to include $8,150 in charitable contributions in its revenue requirement. These contributions were made, pursuant to Section 9-227 of the Act, to 19 universities outside of the utility's service territory (including five in Illinois (total $1,500), one in Wisconsin ($200), two in Indiana ($3,000), and almost all of the rest in nearby States ($3,300) except for $50 and $100 to universities in New York and South Carolina, respectively). Although Staff proposes to disallow these charitable contributions based solely on the fact that these universities are outside of the service territory, Peoples Gas argues it has shown that these contributions are charitable in nature and recoverable under Section 9-227. PGL Ex. 6.0 at 14-15; NS-PGL Ex. 26.0 at 8-9; NS-PGL Ex. 42.0 Rev. at 9. Section 9-227 places a limit on the power of the Commission to disallow reasonable charitable contributions, which Staff's proposal violates. NS-PGL Init. Br. at 110-113. Peoples Gas has also provided detailed information regarding its charitable contributions in its Part 285 Schedules that exceeds

the statutory requirements. PGL Ex. 6.0 at 14-15; NS-PGL Ex. 26.0 at 8-9; NS-PGL Ex. 42.0 at 9.

The Utilities note that Staff relies upon a number of decisions in which the Commission disallowed charitable contributions outside of the utility's service territory, finding that there was no evidence of "any benefit to ratepayers in ComEd's service territory" or that it did not aid the "public welfare." *Commonwealth Edison Co.*, ICC Docket No. 10-0467 (Order May 24, 2011) at 108; *Ameren Illinois Co.*, ICC Docket No. 12-0001 (Order Sept. 19, 2012) at 79. However, the Commission has held that donations made outside of the service territory could be recovered if they benefitted customers in the service territory. *See Commonwealth Edison Co.*, ICC Docket No. 12-0321 (Order Dec. 19, 2012). Moreover, the Utilities argue that Section 9-227 specifically provides for the recovery of contributions "for the public welfare or for charitable scientific, religious or educational purposes…" The Utilities have provided evidence demonstrating that the charitable contributions at issue provide benefits to ratepayers in Peoples Gas' service territory, that these contributions are made for educational purposes, and that donations made outside of the service territory are properly recoverable when found to benefit ratepayers within the territory. NS-PGL Init. Br. at 110-113.

The Utilities also note that CUB-City cite *Ameren Illinois Co.* for the proposition that in difficult economic times, the Commission must closely examine charitable contributions made by Utilities. CUB-City Init. Br. at 48-49. CUB-City fail to note that the *Ameren Illinois Co.* Order also states that economic hardship increases the need for charitable contributions. Moreover, the Utilities maintain that the Order's decision to disallow charitable contributions in an aggregate amount beyond a particular total is factually distinguishable from the case at hand. Order at 31. The Utilities contend that all of the evidence in this proceeding shows the charitable costs are reasonable.

Staff

Staff recommends that the Commission disallow $8,000 in charitable contributions made by Peoples Gas to organizations outside the company's service territory, since there is no tangible evidence that these contributions provide any benefit to Peoples Gas' ratepayers. Staff Ex. 3.0 at 21; Sched. 3.09 P.

Staff explains that Peoples Gas operates a corporate program whereby it matches employee donations to nonprofit organizations. Peoples Gas made matching contributions to colleges and universities located outside of Peoples Gas' service territory. However, it is Staff's position that Peoples Gas failed to provide any tangible evidence that these contributions provide any reasonable benefit to Peoples Gas' ratepayers. Staff Ex. 3.0 at 21-22. According to Staff, its proposed adjustment is consistent with the Commission's recent orders (Docket Nos. 12-0321, 10-0467, 11-0721, and 12-0001) that disallow contributions to organizations outside a utility's service territory. Staff Ex. 13.0 at 21.

Staff argues that its recommended disallowance of test year charitable contributions made by Peoples Gas to organizations outside the company's service territory is appropriate and should be adopted by the Commission.

CUB-City

CUB-City recommend that the Commission adopt Staff's proposed adjustment. CUB-City explain that the Commission addressed the issue of charitable contributions made outside of a utility's service territory in ComEd Docket Nos. 11-0721 and 10-0467 and Ameren Docket No. 12-0001, where such contributions were disallowed. Staff Ex. 3.0 at 22-23. CUB-City point out that although charitable contributions may be considered by the Commission as an operating expense, the Commission has noted concern that, particularly in the current economic climate, "every dollar will make a difference" to ratepayers and thus charitable contributions must be closely examined by the Commission. ICC Docket 11-0282 Final Order of January 10, 2012 at 31. CUB-City aver that charitable contributions are a discretionary expense not necessary for the provision of safe and reliable service. While utilities – like any corporation – are free to make contributions to charities of their choice, CUB-City maintain that the Act contains explicit requirements that must be considered if such costs are to be recoverable from ratepayers. *Id*., 220 ILCS 5/9-227.

CUB-City agree that Staff's adjustment to the Utilities' charitable contributions expense is reasonable and consistent with the Act and previous Commission decisions concerning the limitations of ratepayer-funded charitable expenditures and should therefore be adopted.

Commission Analysis and Conclusion

Section 9-227 of the Act governs which expenses for charitable contributions are recoverable from ratepayers. This section allows the Commission to consider as an operating expense "donations made by a public utility for the public welfare or for charitable scientific, religious or educational purposes, provided that such donations are reasonable in amount." The Commission has recently initiated a rulemaking, Docket No. 12-0457, to develop rules on this issue. However, this rulemaking has not been completed, thus the Commission must resolve this issue based on the current law as it stands today.

All of the charitable contributions that Staff seeks to disallow in this proceeding are to organizations outside Peoples Gas' service territory. The Commission notes that a utility is not precluded from recovering expenses for charitable contributions simply because the organization receiving the donation is outside of the utility's service territory. However, the utility must show that the donation will provide a benefit to customers in its service territory in order to recover these expenses.

The Utilities argue that their donations were made for educational purposes. Additionally, Utilities witness Moy stated that "Illinois universities outside Peoples Gas'

service territory have in the past and currently provide educated utility workers to serve customers and an educated citizenry within the service territory ...". The Commission agrees with the Utilities' reasoning regarding the donations made to Illinois universities and finds that expenses related to these charitable contributions are allowed as operating expenses. The Commission does not believe the Utilities have shown that the charitable contributions to universities outside of Illinois will benefit customers in the Utilities' service territory. Accordingly, the Commission adopts Staff's proposed adjustment to disallow the expenses related to donations made to universities outside Illinois but declines to adopt Staff's proposed adjustment to disallow the expenses related to donations made to universities within Illinois.

d. Institutional Events

Utilities

The Utilities contend that they have demonstrated that their sponsorship of institutional events: (1) supports local charities, (2) serves as a means for the charities to raise contributions, (3) allows for dialogue between the charities and the Utilities so they can better service the community, and (4) fosters cross-collaboration between the Utilities and the community so that the Utilities can better serve their customers. NS-PGL Ex. 26.0 at 9-10; NS-PGL Exs. 26.3N, 26.3P.

The Utilities urge the Commission to disregard Staff's argument to disallow these sponsorships because they are for goodwill advertising and the Utilities already make charitable contributions to some of the same institutions. The Utilities contend that they are not barred from making multiple contributions as long as the amount of such contributions is not unreasonable. Additionally, the Utilities have supported the contribution level and Staff has not proven that it is unreasonable. 220 ILCS 5/9-227; NS-PGL Init. Br. at 113-114.

The Utilities argue that they have provided sufficient evidence to support the finding that certain contributions are made as an element of sponsorship of institutional events, and are not barred by Section 9-225 of the Act. Moreover, Staff has acknowledged that it has not challenged similar sponsorships in previous rate cases and the Commission approved the proposed sponsorships in those cases. NS-PGL Ex. 42.0 Rev. at 10; Staff Ex. 13.0 at 18.

Staff

Staff recommends an adjustment to reduce test year miscellaneous operating expenses associated with annual fund-raising support for institutional events because Section 9-225 of the Act prohibits recovery of these expenses since they are either of a promotional, goodwill or institutional nature and they are not necessary to provide utility service to ratepayers. Staff Ex. 10.0 Supp. at 3.

Staff notes that the Utilities' supporting documentation for annual fund-raising support for institutional events revealed that the Utilities purchased table sponsorships

for their employees to attend breakfast/luncheon/dinner events where the Utilities received recognition in promotional materials and verbal acknowledgement from the event podium. Staff Cross Ex. 5. Staff argues these expenses should not be considered for ratemaking purposes, because such fund-raising support brings the Utilities' names before the general public in such a way as to improve their image. Support of fund-raising events, while promoting good corporate citizenship, are of a promotional and goodwill nature, are not necessary to provide utility service, and provide no direct benefit to ratepayers. Staff Ex. 10.0 at 3-4. Staff asserts that the Act does not allow costs "designed primarily to bring the utility's name before the general public in such a way to improve the image of the utility or to promote controversial issues for the utility or the industry" to be included in rates.

Staff notes that the Utilities agreed that certain annual fund-raising support for institutional events could be considered promotional, goodwill or institutional in nature. NS-PGL Ex. 26.0 at 10. However, Staff states that like the Utilities' acceptance of Staff's disallowance adjustments for advertising expenses discussed above, the Utilities failed to provide a convincing explanation for their acceptance of some of Staff's proposed adjustments. It appears that the Utilities' divided the 2011 events sponsorships into two groups: sponsorships they identified as allowable and the remaining sponsorships they accepted as a part of Staff's disallowance. NS-PGL Ex. 26.3 N and P; Staff Ex. 13.0 at 18; Scheds. 13.04 N and P at 1. Staff does not believe there is any readily apparent difference between the two groups that demonstrates the reasons a sponsorship was or was not deemed allowable for recovery from ratepayers.

Staff asserts that in rebuttal testimony, the Utilities portray support of institutional events as charitable contributions. NS-PGL Ex. 26.0 at 9-10. Staff argues this portrayal is misleading. The Utilities already make charitable contributions to a number of these organizations in addition to providing support for their fundraising events. Whether the Utilities record institutional events support costs as miscellaneous general operating expense or charitable contributions, should not dictate whether these particular miscellaneous general operating expenses should be recovered from ratepayers. Staff further argues that the Utilities have provided no evidence that the costs of their fund-raising event sponsorships are anything other than goodwill advertising costs, which are barred from cost recovery by the Act. Staff Ex. 13.0 at 18-19. Therefore, Staff contends its recommended adjustment is appropriate and should be adopted by the Commission.

CUB-City

CUB-City recommend that the Commission adopt Staff's adjustments. CUB-City argue such advertising is expressly prohibited by Section 9-225 of the Act. While the Companies agreed to certain of Mr. Ostrander's adjustments, they continue to seek recovery of certain events they admit include name recognition, food and "entertainment," claiming they provide "public welfare and educational benefits." NS-PGL Ex. 26.0 at 9-10. CUB-City agree with Staff's position that characterizing these events as charitable is misleading since the Utilities already make charitable contributions to a number of these organizations in addition to providing support for their

fundraising events. Staff Ex. 13.0 at 18-19. CUB-City argue that the Commission should not be persuaded by the Companies' attempt, in the rebuttal phase of this case, to re-characterize these costs as charitable.

Commission Analysis and Conclusion

The Commission finds that the contributions made by the Utilities as an element of sponsorship of institutional events are recoverable under the Act as operating expenses. The Utilities have provided sufficient evidence to show that these contributions were made to support fundraising events for local charities and communities in the Utilities' service territory and not primarily to promote the Utilities or foster goodwill towards the Utilities. In addition, multiple contributions to an entity are not prohibited by the Act as long as the combined amount of the contributions is not unreasonable. There is no evidence that this is the case. The Commission concludes that these costs are not barred by Section 9-225 of the Act and are recoverable under Section 9-225 and 9-227. Therefore, the Commission rejects Staff's adjustments.

8. Depreciation

a. Bonus Depreciation

The contested issues with respect to bonus depreciation are discussed in Section IV.C.6.c.

b. Derivative Adjustments from Contested Adjustments

This is an uncontested issue that depends on the outcome of other issues discussed elsewhere in this Order. The Commission's conclusions are reflected in the Appendices.

9. Rate Case Expenses

Utilities

The Utilities take the position that the evidentiary record contains substantial evidence demonstrating that their revised proposed rate case expenses for this rate case – $2.286 million for North Shore and $3.334 million for Peoples Gas – are just and reasonable. NS-PGL Ex. 42.0 Rev. at 12-13; NS-PGL Exs. 42.4N, 42.4P; Staff Ex. 13.0 at 8-9 and Scheds. 13.01N, 13.01P. The Utilities assert that the record evidence is more than sufficient for the Commission to specifically assess the justness and reasonableness of those expenses as required by Section 9-229 of the Act. The Utilities further rely on the fact that the Staff witnesses who examined the voluminous evidence the Utilities introduced into the record to support the recovery of their rate case expenses concluded that the amounts sought by the Utilities were just and reasonable based on that evidence. Staff Ex. 13.0 at 4-9 and Scheds. 13.01N, 13.01P; Staff Ex. 17.0 at 19; Staff Ex. 22.0 at 2. The Utilities further request that these rate case expenses be amortized over two years for ratemaking purposes, based on the Utilities' experience as to the time between its past rate cases and the requirements of the Act

relating to the expected timing of the Utilities' next two general rate case filings. NS Ex. 6.0 at 13; PGL Ex. 6.0 at 13.

The Utilities state that it is well-established law that a utility is entitled to recover rate case expenses, which have been found by the Supreme Court of Illinois to be ordinarily, properly and fairly allowable as an operating expense. *DuPage Util. Co. v. Illinois Commerce Comm'n*, 47 Ill. 2d 550, 553 and 561 (1971) ("rate-case expense is ordinarily properly and fairly allowed as an operating expense"). *See also People ex rel. Lisa Madigan v. Illinois Commerce Comm'n*, 2011 IL App (1st) 101776, ¶ 13 (1st Dist. Dec. 9, 2011) ("*Illinois-American Water*"), *appeal denied* (Ill. S. Ct. Sept. 26, 2012) ("Illinois courts have allowed utilities to recover rate case expense because '[t]he costs incurred by a utility to prepare and present a rate case are properly recoverable as an ordinary and reasonable cost of doing business.'") (citations omitted). The guiding standard for the Commission in setting any rates for a public utility – that the rates be "just and reasonable" – extends to a public utility's recovery of rate case expenses in its rates, as well. *See*, *e.g.*, *Northern Illinois Gas Co.*, ICC Docket No. 04-0779 (Order Sept. 20, 2005) at 51 ("The amortization period for rate case expense is guided by the requirement that the final rates be just and reasonable"); *Consumers Illinois Water Co.*, ICC Docket No. 03-0403, (Order (April 13, 2004) at 22 ("the components of . . . rates, including rate case expense, must themselves be just and reasonable").

The Utilities' position is that Section 9-229 of the Act did not change this standard, as Section 9-229 expressly mandates that "justness and reasonableness" is the standard by which rate case expenses must be judged. Rather, Section 9-229 places an additional requirement on the Commission to "specifically assess the justness and reasonableness" of a public utility's rate case expenses and expressly address this issue in its final order in a rate case proceeding. The appellate court in *Illinois-American Water* held that this language in Section 9-229 requires the Commission to "expressly address the basis for its findings" – *i.e.*, include "explanation or discussion" – as to the justness and reasonableness of a public utility's rate case expenses in its final order. *Illinois-American Water*, 2011 IL App (1st) 101776 at ¶¶ 47-48. With respect to the type of information the Commission should address in making this finding, the appellate court in *Illinois-American Water* in dicta suggested that the Commission could look to cases involving the award of attorney fees in the context of statutory or contractual fee-shifting provisions. *Id*. at ¶ 51. Based on this guidance, the Commission has stated that a public utility must provide detailed information concerning what actual expenses have been or will be incurred, by whom, for what purpose and why such expenses were necessary in order for the Commission to make an informed determination regarding the justness and reasonableness of recovering rate case expenses from customers. *See In re Charmar Water Co., et al.*, ICC Docket Nos. 11-0561 – 11-0566 (consol.) (Order May 22, 2012) at 19; *In re Charmar Water Co., et al.*, ICC Docket Nos. 11-0561 – 11-0566 (consol.) (Order on Rehearing Nov. 28, 2012) at 14.

The Utilities state that the evidentiary record in this rate case contains an abundance of detailed information presented by the Utilities establishing the actual expenses that have been or will be incurred, the persons providing the services for

which those expenses were billed to the Utilities, what services were performed and for what purpose, and why those services were necessary. The record also contains evidence concerning the skill and experience of the attorneys and technical experts, the negotiation of rates, the nature and complexity of the work involved, the comparability of those rates to market rates for similar attorneys and technical experts of their skill and experience levels, and the comparability of rates and the amounts charged in other rate cases before the Commission. With respect to their rate case expenses generally, the unrebutted record evidence established that the Utilities: (1) work to achieve efficiencies in rate case expenses from the simultaneous preparation and consolidation of their rate case proceedings, (2) select outside counsel and expert resources with extensive experience both in Illinois rate cases and related proceedings generally and with the Utilities specifically; (3) negotiate appropriate estimated hours of work that would be reasonable for the scope of and matters reasonably expected to be involved in these rate cases, as well as hourly rates that are just and reasonable in light of the market rates for experienced counsel and technical experts in Chicago generally and for practice before the Commission in Chicago specifically; (4) use IBS cost effectively to provide rate case support services; and (5) need outside counsel and technical experts to assist with the extensive procedures involved in prosecuting their rate cases after they were filed, including the discovery process, analysis of Staff and intervenor direct and rebuttal testimonies, assistance with preparation of the Utilities' rebuttal and surrebuttal testimonies, the evidentiary hearing, post-hearing briefs and reply briefs, analysis of the Administrative Law Judges' Proposed Order, briefs and reply briefs on exceptions, preparation and participation in oral argument, analysis of the final Commission Order, and preparation of a compliance filing. NS Ex. 6.0 at 16-18; PGL Ex. 6.0 at 16-18.

The Utilities state that the evidence also demonstrates the justness and reasonableness of the Utilities' rate case expenses in that the Utilities negotiated agreements with their outside legal counsel whereby their bills would not exceed established budgeted amounts estimated for the work necessary to prepare and litigate the rate cases. Further, the Utilities' witness testified that the Utilities review the invoices submitted by their outside legal counsel and consultants to ensure that they describe the work being performed, no unreasonable amounts of time have been billed for particular tasks, and there has not been inappropriate redundancy whereby multiple counsel or consultants unnecessarily bill time for performing the same task on the same project. The Utilities required that both their affiliated IBS employees and outside consultants working on the rate cases provide detailed invoices. With respect to amounts charged by IBS employees, the Utilities review the documentation to ensure that there is no "double-counting" of expenses for rate case work performed by IBS personnel. NS Ex. 6.0 at 18; PGL Ex. 6.0 at 18. Additionally, the Utilities' rate case expenses witness, Ms. Moy, testified during the hearing that based on her experience in prior rate cases and information from persons who deal directly with the attorneys and technical experts involved in the rate cases, the amounts of estimated rate case expenses remaining that had not been incurred by the time of the hearing are likely to be incurred by the end of the suspension period in June, 2013. Tr. at 103- 104.

Specifically for each law firm and consultant, the Utilities note that they provided voluminous record evidence containing detailed information concerning what actual expenses have been or will be incurred, by whom, for what purpose and why such expenses were necessary, which establishes the justness and reasonableness of their costs that are sought to be recovered as rate case expenses.

The Utilities also seek recovery of the remaining amount of rate case expense approved but unrecovered in their 2009 and 2011 rate cases. The Utilities state that if the Commission approved the recovery of rate case expense in a prior rate case to be amortized over a number of years, and the utility files another rate case before the recovery period has been completed, then it is appropriate for the Commission to include the amount of previously approved but unrecovered rate case expense to be recovered in the subsequent rate case expense amortization period. *See generally Illinois American Water*, 2011 IL App. (1st) 101776 at ¶¶18-37; 83 Ill. Admin. Code § 285.3085(d) ("If amortization of previous rate case expenses are included within test year jurisdictional operating expense at proposed rates on Schedule C-1, provide the amount of amortization expense associated with each rate case by docket number."). The Utilities note that no party submitted testimony opposing the recovery of these expenses, and the Utilities agreed to adjust the 2011 rate case expense amounts as proposed by Staff. NS-PGL Ex. 42.0 Rev. at 12; Staff Ex. 13.0 at 5.

Finally, the Utilities state that they have incurred rehearing and/or appeal costs related to both their 2009 and 2011 rate cases for which they seek amortized recovery as part of the rate case expenses in the present cases. The Utilities assert that, as the Commission concluded in *Peoples Gas 2011*, "rehearing and appeal expenses are part and parcel of the litigation expenses in most every significant rate case proceeding," and that nothing in Section 9-229 of the Act prohibits the Commission from allowing their recovery in a subsequent rate case. *Peoples Gas 2011* Order *at* 85-86 (approving amortized recovery of rehearing and appeal costs for the Utilities' 2009 rate cases as part of the Utilities rate case expenses in their 2011 rate cases). The record evidence contains detailed invoices introduced by the Utilities related to the rehearing and/or appeals of both their 2009 and 2011 rate cases that identify each attorney or support staff (*i.e.*, paralegal) who has billed time to the rate cases, describe the services performed with detailed daily time entries stating the amount of time expended and describing what was done during that time, and the hourly rate charged. NS-PGL Ex. 26.0 at 15; NS-PGL Ex. 42.0 Rev. at 19-20; NS-PGL Ex. 26.19 (2009 rate cases); NS-PGL Exs. 26.20 and 42.12 (2011 rate cases).

The Utilities note that no party has submitted testimony opposing or challenging the recovery of their rehearing and/or appeal expenses. The Utilities state that, as concluded by the Commission in *Peoples Gas 2011*, recovery of such expenses is appropriate and the Commission should approve recovery of the rehearing and/or appeal costs for the Utilities' 2009 and 2011 rate cases in the same two-year amortization period sought for rate case expenses from the current proceedings.

The Utilities conclude that for these reasons, the Commission should make a determination pursuant to Section 9-229 of the Act, 220 ILCS 5/9-229, that the $2.286 million and $3.334 million in rate case expenses requested by North Shore and Peoples Gas, respectively, in these dockets are just and reasonable and allow their recovery (as well as recovery of the unamortized amounts of rate case expenses remaining, and rehearing and appeal costs, from previous rate cases) over a two-year amortization period.

Staff

Staff proposed adjustments to correct the amortization of the rate case expenses approved by the Commission in the Utilities' 2011 rate cases, which the Utilities accepted. Staff did not recommend any other adjustments to the rate case expenses proposed by the Utilities.

Staff recommends that the Order in this proceeding express a Commission conclusion as follows:

> The Commission has considered the costs expended by the Companies to compensate attorneys and technical experts to prepare and litigate these rate case proceedings and assesses that the amounts included as rate case expense in the revenue requirements of $2.286 million and $3.334 million for North Shore and Peoples Gas, respectively, are just and reasonable.

Staff believes the Commission should include this language in light of Section 9-224 of the Act.

CUB-City

CUB-City recommend that the Commission adopt the adjustment proposed by Staff witness Mr. Ostrander and accepted by the Utilities to correct the amortization of rate case expenses for the Utilities' 2011 rate cases. CUB-City maintain the Utilities did not use the amount of rate case expense approved in that docket in calculating their test year amortization expense. Additionally, CUB-City recommend that the Commission examine NS-PGL Exs. 42.4 N and P to determine whether it is likely that the Utilities will actually spend their budgeted rate case expense, based upon amounts expended through the time of surrebuttal.

Commission Analysis and Conclusions

"The costs incurred by a utility to prepare and present a rate case are properly recoverable as an ordinary and reasonable cost of doing business." *Illinois-American Water*, 2011 IL App (1st) 101776 at ¶ 13 (citations omitted). The guiding standard for the Commission in setting any rates for a public utility – that the rates be "just and reasonable" – extends to a public utility's recovery of rate case expenses in its rates, as

well. *See*, *e.g.*, *Northern Illinois Gas Co.*, ICC Docket No. 04-0779 (Order Sept. 20, 2005) at 51 ("The amortization period for rate case expense is guided by the requirement that the final rates be just and reasonable"); *Consumers Illinois Water Co.*, ICC Docket No. 03-0403, (Order (April 13, 2004) at 22 ("the components of . . . rates, including rate case expense, must themselves be just and reasonable").

Section 9-229 of the Act explicitly states that the Commission is required to closely review these expenses. Section 9-229 provides:

> Consideration of attorney and expert compensation as an expense. The Commission shall specifically assess the justness and reasonableness of any amount expended by a public utility to compensate attorneys or technical experts to prepare and litigate a general rate case filing. This issue shall be expressly addressed in the Commission's final order.

220 ILCS 5/9-229. The appellate court in *Illinois-American Water* held that Section 9-229 requires the Commission to "'expressly address' the basis for its findings" – *i.e.*, include "explanation or discussion" – as to the justness and reasonableness of a public utility's rate case expenses in its final order. *Illinois-American Water*, 2011 IL App (1st) 101776 at ¶¶ 47-48. Based on the guidance provided by the court in *Illinois-American Water*, the Commission has stated that a public utility must provide detailed information concerning what actual expenses have been or will be incurred, by whom, for what purpose and why such expenses were necessary in order for the Commission to make an informed determination regarding the justness and reasonableness of recovering rate case expenses from customers. *See In re Charmar Water Co., et al.*, ICC Docket Nos. 11-0561 – 11-0566 (consol.) (Order May 22, 2012) at 19; *In re Charmar Water Co., et al.*, ICC Docket Nos. 11-0561 – 11-0566 (consol.) (Order on Rehearing Nov. 28, 2012) at 14.

The Commission notes that it has initiated a rulemaking in Docket No. 11-0711 to develop rules regarding the issue of rate case expense. The rulemaking will establish clear criteria, procedural, and evidentiary standards to justify attorneys' and expert compensation under Section 9-229. This rulemaking has not yet been completed thus this issue will be resolved without the benefit of the forthcoming standards.

The Commission has thoroughly examined the voluminous record evidence supporting the rate case expenses for which North Shore and Peoples Gas have requested recovery in this rate case. The Commission finds that for each of the attorneys and technical experts for which recovery of rate case expense is sought, the Utilities provided detailed information concerning the nature and scope of their engagement, their hourly rates, what services they performed in support of the rate case, why those services were necessary, and what their actual expenses have been or will be incurred. Detailed invoices were provided that identified who was performing the work, what work or tasks were performed, when and for how long, and the fees and

costs associated with that work. Further, the record evidence demonstrates that the rates negotiated with the attorneys and experts were reasonable in light of their experience working on rate cases generally and for the Utilities specifically, the market rate for such services, discounts and other cost protections such as "not-to-exceed" provisions provided, and the necessity and level of difficulty of the work to be performed. The record evidence also established that the Utilities review the invoices and have other safeguards in place to ensure that there is no "double-counting" for the costs of work performed by IBS personnel and that the time spent performing work by outside counsel and experts is reasonable and not duplicative. Moreover, while not determinative of the issue, the Commission notes that no party opposed recovery of the final revised amounts of rate case expenses sought by the Utilities, and that Staff testified that it had reviewed the record evidence and found the amounts requested to be just and reasonable based on the facts and circumstances of this rate case.

Additionally, the Commission finds that the evidence in the record supports the conclusion that the amount of rate case expenses not actually shown to have been expended by the time of the hearing are reasonably likely to be expended by the end of the rate case.

The Commission has considered the costs expended by the Utilities to compensate attorneys and technical experts to prepare and litigate these rate case proceedings and assesses that the amounts included as rate case expense in the revenue requirements of $2.286 million and $3.334 million for North Shore and Peoples Gas, respectively, are just and reasonable. The Commission also finds that the recovery of North Shore's and Peoples Gas' unamortized amounts of rate case expenses remaining, as well as rehearing and appeal costs, from previous rate cases to be just and reasonable. The Commission approves the recovery of these expenses over a two-year amortization period.

D. Taxes Other Than Income Taxes and Invested Capital Taxes (Payroll) (Uncontested Except for Invested Capital Tax and Derivative Adjustments from Contested Adjustments)

1. Invested Capital Tax Computation and Derivative Adjustments

Utilities

The Utilities propose a methodology for computing invested capital tax and its derivative adjustments based upon 2013 invested capital; Staff agrees with this proposed methodology. Staff Ex. 14.0 at 19-21. The Utilities argue that the AG and CUB-City each set forth a proposal that either bases the invested capital tax calculation on 2012 invested capital amounts and balances or based the accruals recorded for the 2013 test year. The Utilities state that their estimated and accrued tax obligation should be based on 2013 invested capital beginning and ending balances as prescribed by law (35 ILCS 615/1 and 615/2a.1) and not be estimated and accrued based on 2012 beginning and ending balances. NS-PGL Ex. 46.0 at 37-38. This should be the application for computing 2013 test year cost of service, as well as computing the Utilities' actual 2013 activity for financial accounting purposes. *Id.* At December 31,

2013, all events would have occurred that will bind the Utilities to paying this tax obligation based on 2013 invested capital activity and balances. *Id.* Further, the Utilities argue that the fact that the 2013 invested capital return is not filed until 2014 does not change the Utilities' obligation to calculate 2013 accruals based on 2013 activity and balances. *Id*. The Utilities also note that accruing a tax expense in 2013 that results from the 2012 taxable period would be inconsistent with GAAP. NS-PGL Rev. 30.0 Rev. at 35.

Finally, the Utilities state that derivative adjustments are necessary as a result of the invested capital tax computation. The Utilities argue that the AG's arguments that derivative adjustments are not necessary are based on the inaccurate assumptions that (1) other adjustments in revenues and expenses related to regulatory disallowances and financing charges were not taken into account by the Utilities; and (2) the Utilities' proposed rate of return and rate base filed in direct testimony are approved. NS-PGL Ex. 26.0 at 10. Throughout the proceeding, the Utilities' common equity and rate of return have changed based on updates to rate base and operating income adjustments. See NS-PGL Exs. 23.1N, 23.2N, 23.1P and 23.2P. Further, the Utilities add that rate base and operating income adjustments reflect the variations in revenues, expenses, financing charges, and proposed disallowances accepted by the Utilities. NS-PGL Ex. 26.0 at 11. Thus, the Utilities conclude that their invested capital changed over the course of the proceeding. As such, these adjustments should be factored into the derivative adjustments for invested capital taxes as it represents. *Id*.

Staff

Staff proposed adjustments to update the calculation of invested capital tax to synchronize with the final revenue requirements that are ultimately approved by the Commission for the Utilities in this proceeding. Staff Ex. 4.0 at 21 – 23; Scheds. 4.04 N and P. Staff's proposed methodology is consistent with the methodology approved by the Commission in the Utilities' previous rate cases, Docket Nos. 11-0280/11-0281 (Cons.) and Docket Nos. 07-0241/07-0242 (Cons.). The Utilities accepted Staff's proposed methodology.

Staff reasoned that a future test year is based on forecasted amounts, and therefore a forecasted invested capital tax that is synchronized with the final revenue requirements that are ultimately approved by the Commission in this proceeding will more closely approximate this expense during the period these rates are in effect than will the actual amount paid during 2013 because that amount excludes the impact of additional investments made during the test year.

AG

The AG disagrees with the Utilities' proposed methodology for computing invested capital tax and its derivative adjustments. AG witness Brosch testified that the Utilities' proposed methodology, includes expected 2014 amounts within a 2013 test year, results in a mismatching of test year expenses which is improper and serves to

overstate the revenue requirement. AG Ex. 1.0 at 42. Mr. Brosch further testified that the Utilities' derivative adjustments are unnecessary.

Like CUB-City, the AG contends that the Utilities invested capital tax expense for a 2013 test year should be based on its 2012 invested capital beginning and ending balances. As explained by Mr. Brosch, the Utilities' proposed amounts are overstated because the taxes calculated by them are based on estimated investment levels in 2013, and would not be payable or expensed on the books until after 2013. The AG states that the Utilities admitted that "The Illinois Invested Capital tax is recorded on the books as a monthly accrual. The monthly accrual is based upon last year's tax divided by twelve (months)." For this reason, the AG maintains the estimated tax calculation for the 2013 test year should mirror the inputs that will appear on the tax return to be filed by March of 2013, based upon beginning and end-of-year 2012 invested capital balances. *Id.* at 44.

The AG maintains that another reason the Utilities' proposed test year expenses are overstated is because the Utilities also propose an adjustment to include additional tax dollars for an alleged prospective impact from a rate increase in the instant dockets. The AG argues that such an adjustment does not accurately predict future invested capital taxes in the test year and rate changes alone cannot be shown to accurately define test year invested capital tax expense levels.

The AG avers that a tax return that includes financial data for an annual period for the invested capital tax of 2013 as proposed by the Utilities will not be filed until 2014. As Mr. Brosch noted in his Direct Testimony, the taxes calculated by Peoples Gas and North Shore that are based on estimated investment levels in 2013 would not be payable or expensed on the books until after 2013. Thus, the Utilities' proposed methodology actually yields an estimated tax expense for the following tax year, calendar 2014. The AG argues that it is not reasonable to include within a 2013 test year estimated invested capital expenses that are not payable until 2014 and will not be recorded on the Utilties' books until 2014. AG Ex. 4.0 at 43.

For all of the reasons presented above, the AG recommends that its proposed adjustment to this expense item be adopted.

CUB-City

CUB-City aver that the Utilities computation of their invested capital tax uses accruals of invested capital tax that, according to the Utilities' original descriptions of their accounting, would be recorded in 2014 – one year beyond the 2013 test year. CUB-City Ex. 2.0 at 13 -14. CUB-City note that the Utilities' chose a 2013 test year for this case, and the amount of invested capital tax included in the revenue requirement should be based on expenses that are expected to be recorded in 2013. *Id*. at 14-80.

CUB-City explain that the amount of invested capital tax accrued in each year is based on the invested capital tax shown on a utility's return for the prior year. CUB-City

Ex. 2.0 at 12. The amounts for invested capital tax recorded in 2012 were based on monthly and quarterly amounts that were derived from the invested capital tax shown on the Utilities' tax return for the prior year. CUB-City Ex. 2.0, 12, *citing* AG 10.13 (included at CUB-City Ex. 2.1 at 8-9). CUB-City aver that the Commission's objective should be to identify the best estimates of the amounts of invested capital tax that will be recorded as expenses on the Utilities' books during the 2013 test year that is being used as the basis for determining the Utilities' revenue requirement. CUB-City Ex. 2.0 at 12. CUB-City note that the Utilities have stated in numerous places that the estimated tax liability amounts to be recorded as expense for invested capital tax in an accounting year are based upon the amounts shown in last year's tax return. As one example of this, the Utilities' response to AG 8.20(c) states that:

> **The Illinois Invested Capital tax is recorded on the books as a monthly accrual. <u>The monthly accrual is based upon last year's tax divided by twelve (months)</u>.** Additionally, quarterly estimated tax payments are made against this accrual. These quarterly estimated tax payments are also based upon last year's tax divided by four (quarters).

CUB-City Ex. 2.1 at 8-9 (emphasis added).

Thus, CUB-City argue, the amount for ratemaking for a 2013 test year should in turn be based on the amounts shown on the Utilities' 2012 tax returns. CUB-City Ex. 2.0 at 12. An accurate statement of the Utilities' invested capital tax expense should be based on its 2012 invested capital tax amount – computed in the same manner that the Utilities admit they will accrue that expense (a monthly accrual of the prior year's tax divided by twelve). *Id.* CUB-City's recommendation reflects the Utilities' accrual accounting in estimating the amount of 2013 test year invested capital tax.

Commission Analysis and Conclusion

The Commission finds that the Utilities' proposed methodology for computing invested capital tax and derivative adjustments using 2013 invested capital beginning and ending balances in their calculation for their 2013 invested capital return is appropriate and consistent with applicable accounting principles. The Commission also finds that the Utilities have provided sufficient evidence to show that derivative adjustments are necessary because of the Utilities' ongoing adjustments to revenues and expenses and the fact that the Utilities' rate of return and rate base have not yet been approved. Accordingly, the Commission declines to adopt the adjustments related to invested capital tax proposed by the AG and CUB-City.

E. Income Taxes (Including Interest Synchronization) (Derivative Adjustments from Contested Adjustments)

1. Appropriate Methodology to Reflect Change in State Income Tax Rate (see also Section V.C.6.a.)

The contested issues with respect to bonus depreciation are discussed in Section IV.C.6.a.

F. Gross Revenue Conversion Factor

1. Methodology

The only contested issue with respect to the Utilities' Gross Revenue Conversion Factors is addressed in Section V.F.2.

2. Late Payment Charge Ratio

Utilities

The Utilities argue that they have accounted for late payment charge revenues in their direct cases, ensuring that this revenue is accurately reflected in the Utilities' calculations. NS-PGL Ex. 26.0 at 12-13, NS-PGL Ex. 42.0 Rev. at 11. The AG's Initial Brief, as the Utilities understand it, does not contend otherwise. Instead, the AG acknowledges that "it is true that PGL and NS have accounted for incremental Late Payment Charge revenues arising from the rate increase…." AG Init. Br. at 95.

The Utilities maintain that the AG miscalculated these charges by assuming operating revenues of over 100%, and appeared to propose a change to the Utilities' Gross Revenue Conversion Factors that would result in a double-counting of these charges. NS-PGL Init. Br. at 129-130.

The Utilities state that to the extent, however, that the AG's Initial Brief has clarified that the AG proposal is meant not to operate as an adjustment to the Utilities' figures but only within the AG's Schedules, it still is unnecessary and remains incorrectly calculated. The AG's Initial Brief, as the Utilities understand it, contends in essence that, the way the AG presented their schedules and calculated the incremental late payment charge revenues within the context of the AG schedules has a different form but it ultimately also correctly calculates those revenues. AG Init. Br. at 95-96. Nonetheless, if the AG is suggesting that its different format be used, the AG has given no reason for doing so, and, if it were to be adopted then the Utilities' calculations would need to be modified to avoid double-counting of the incremental late payment charge revenues. In addition, the AG calculation is not correct, in any event, because it assumes operating revenues of over 100%. NS-PGL Ex. 42.0 Rev. at 11. The Utilities conclude that the AG proposal as an incremental proposal can and must be rejected as double-counting, there is no reason to substitute it, and, as calculated, it is erroneous.

AG

The AG observes that Companies witness Moy takes issue with the Gross Revenue Conversion Factor set forth in AG Schedule A-1, where part of the required revenue increase is satisfied by a ratable increase in Late Payment Charge revenues.

According to Ms. Moy, "The Utilities have already accounted for the fact that every dollar of incremental base rate revenue will create incremental late payment charge revenues in the revenue requirement. Thus, Mr. Brosch's adjustment would result in double counting."

The AG argues that there is no "double counting" of incremental late payment charge revenues under its approach. While it is true that PGL and NS have accounted for incremental late payment charge revenues arising from the rate increase at NS-PGL Ex. 26.1P/N in column (F) at line 10, it is important to note that the starting point for the AG's revenue requirement calculations is column (E) of this Exhibit, which is prior to such incremental late payment charge revenues. This fact can be verified by looking at AG Exhibit 4.1 in Schedule C, where PGL's "Other Revenues" in column (B) are $15,386 (thousand) which does not include the incremental $885 (thousand) of incremental late payment charge revenues arising from PGL's proposed revenue increase. The AG asserts that an accounting for these "Other Revenues" is therefore needed in AG Schedule A-1, the Gross Revenue Conversion Factor, to accomplish the same accounting for incremental late payment charge revenues from the revenue increase that the Companies apparently agree should be recognized. The AG's proposed revenue conversion factor on Schedule A-1 includes a factor at line 2 to "Add: Other Operating Revenues" that has the effect of including late payment charge revenue growth associated with the AG-proposed revenue requirement, which amounts then appear in Schedule C, page 1, column (E), line 3 for each of the Companies. AG Ex. 4.0 at 4-5.

For these reasons, the AG maintains that Ms. Moy's criticisms of Mr. Brosch's calculation of the late payment charge revenues within the Gross Revenue Conversion factor should be rejected.

Commission Analysis and Conclusion

The Commission finds that the Utilities have properly accounted for late payment charge revenues in their calculations. The AG's proposed adjustment is therefore unnecessary and would result in a double-counting of late payment charge revenues. Therefore, the Commission rejects the AG's proposal.

G. Net Operating Loss (Derivative Adjustment based on NOL Tax Asset)

The Commission's conclusions reflected in the Appendices are consistent with its findings in Section IV.C.5 of this Order.

VI. RATE OF RETURN

A. Overview

Peoples Gas proposes a rate of return on rate base of 7.07% based on a capital structure comprised of 50.43% common equity at a cost (a rate of return on common equity or "ROE") of 10.00%, 43.61% long-term debt at a cost of 4.47%, and 5.96% short-term debt at a cost of 1.26%. North Shore proposes a rate of return on rate base

of 7.12% based on a capital structure comprised of 50.32% common equity at an ROE of 10.00%, 42.33% long-term debt at a cost of 4.64%, and 7.35% short-term debt at a cost of 1.80%. The Utilities' proposed 10.00% ROE represents a modest increase to their current ROE of 9.45%.

The Utilities' capital structures and short-term debt costs are not disputed. The Utilities and Staff are in agreement on the Utilities' long-term debt costs, but the AG proposes slightly lower costs by assuming that the Utilities' 2013 debt issuances will cost the same as the actual cost of Peoples Gas' new debt issuance in late 2012 instead of current or forecasted costs for the 2013 issuances. (CUB-City did not address long-term debt cost in their initial brief.)

Staff proposes substantially lower rates of return on rate base, 6.60% for Peoples Gas and 6.65% for North Shore, by virtue of its proposal to reduce the Utilities' ROE from 9.45% to 9.06%. The AG and CUB-City support Staff's proposed ROE.

The legal standards governing a public utility's entitlement to a fair and reasonable return on its investment are well established and familiar. The Commission summarized these standards in one of the Utilities' recent rate cases thus:

> A public utility has a constitutional right to a return that is 'reasonably sufficient to assure confidence in the financial soundness of the utility and adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.' The authorized return on equity 'should be commensurate with returns on investments in other enterprises having corresponding risks. That return, however, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.'

Peoples Gas 2009 Order at 89-90 (citations omitted).

B. Capital Structure (Uncontested)

As shown in their respective cost of capital schedules, the Utilities and Staff agree on the following capital structures. NS-PGL Exs. 38.1N & 38.1P; Staff Ex. 15.0, Sched. 15.01. No party disputed these structures.

	Peoples Gas	**North Shore**
Common Equity	50.43%	50.32%
Long-Term Debt	43.61%	42.33%
Short-Term Debt	5.96%	7.35%

According to the Utilities, these structures comply with Section 9-230 of the Act because they are consistent with and will support the Utilities' current stand-alone credit ratings. NS Ex. 2.0 at 5-7; PGL Ex. 2.0 at 5-7. A strong capital structure is important, the Utilities assert, because it helps insulate the utility from financial shocks and reduces its cost of debt that is passed on to customers. NS Ex. 2.0 at 7; PGL Ex. 2.0 at 7.

The Commission finds that the undisputed capital structures agreed to by the Utilities and Staff are reasonable and consistent with the Act, and therefore approves them.

C. Cost of Short-Term Debt (Uncontested)

The Utilities and Staff agree on a short-term debt cost of 1.26% for Peoples Gas and 1.80% for North Shore. NS-PGL Exs. 38.1N and 38.1P; Staff Ex. 15.0, Sched. 15.01. No other party addressed short-term debt in their briefs.

Because these rates reflect consideration of both recent actual interest rates and recent forecasts of interest rates during the test year, the Commission finds them reasonable and approves their inclusion in the Utilities' 2013 rates.

D. Cost of Long-Term Debt

Utilities

The Utilities accepted Staff's 4.47% cost of long-term debt for Peoples Gas and 4.64% for North Shore. NS-PGL Ex. 38.0 at 3-4. Peoples Gas requested that its long-term debt cost be adjusted to reflect the anticipated April 2013 refinancing of its Series KK bonds at lower cost.

The AG proposes slightly lower costs, arguing that the Utilities' rates should reflect the Utilities' 2013 bond issuances at the same cost as Peoples Gas' November 2012 bond issuance (3.98%). AG Init. Br. at 97-98. This approach is not reasonable, the Utilities respond, because (1) their debt costs should be based on analyst forecasts of the cost of A-rated utility debt in 2013 and (2) even if actual costs are considered, the 4.20% cost proposed by Staff is based on more recent actual A-rated utility bond rates, which is more accurate actual cost data than the AG's single historical rate. NS-PGL Reply Br. at 121-122.

The Utilities also object to the AG's proposal to base their long-term debt costs on a year-end measure. Acknowledging that the AG's proposal would not significantly impact their overall rate of return, the Utilities argued that a year-end measure of long-term debt costs would create a mismatch between their rates and their forecasted costs. The Utilities pointed out that measuring these costs on an annual average basis id consistent with the Commission rule that allows long-term debt balances to be established on an annual average basis. Ill. Adm. Code § 285.4000(b). NS-PGL Init.

Br. at 134. Furthermore, where as here, the Utilities anticipate retiring some of their long-term debt and issuing new debt during the test year, using an annual average will result in rates that more accurately represent their forecasted cost throughout the year. *Id.* at 135. By contrast, if the Utilities' rates reflected forecasted year-end balances of long-term debt, they would reflect only the financing employed by the Utilities on that date. *Id.* The resulting cost would be inaccurate because it would not reflect the higher cost debt retired earlier in the year and would reflect the lower cost debt issued during the year as if it were issued at the beginning of the year. *Id.* In each case, the resulting rates would be inaccurate.

Although a year-end measure would result in slightly lower long-term debt costs in this case (because higher cost debt is anticipated to be replaced with lower cost debt during the test year) the Utilities caution that customers would be over-charged if the cost of the replacement debt was anticipated to be higher than retired debt. In either case, the Utilities argue, their rates would not accurately reflect their forecasted costs. *Id.* at 136; *see also* NS-PGL Reply Br. at 123.

AG

There are two disputed issues with regard to the cost of long term debt. The first issue is factual and involves how to best determine the cost rates to be used for new issuances of debt that are planned to occur within the test year using an average cost calculation methodology. The second issue is conceptual and relates to the Companies' proposed use of a year-end rate base to increase revenue requirements at the same time the Companies' are resisting use of the lower annualized cost rate for long term debt *as of year-end* that would reduce revenue requirements by fully reflecting debt cost savings arising from refinancing of older, higher-cost debt. This second issue is conditioned upon Commission acceptance of a year-end rate base, as proposed by the Companies (see separate discussion of this issue in the Year-End Rate Base Section, infra), which acceptance should dictate consistent utilization of a year-end long term debt cost rate that annualizes the savings realizable by the Companies from the debt refinancing transactions scheduled to occur within the test year.

With respect to the first, factual issue, the Companies' respective Revised Schedule D-1 reveal that NS proposes a 4.64% cost of long term debt, and PGL proposes a 4.47% cost. NS-PGL Ex. 38.0 at 2; NS-PGL Exs. 38.1N and 38.1P. These amounts are quantified using an average cost rate for all debt outstanding during the test year, including periods before and after the refinancing of certain older, higher-cost debt. AG witness Brosch recommends a slight adjustment to both of these figures, also using an average cost rate approach: to 4.60% for NS and 4.46% for PGL. AG Ex. 4.1, Sched. D; AG Ex. 4.2, Sched. D. Although the recommended adjustments are slight, they are nonetheless important because they seek to more appropriately reflect the Companies' *actual* long term debt costs.

The Companies' calculation of Long Term Debt cost overstates the expected interest coupon rates for each of the forecasted new issuances. The Company's

estimated cost rates were based upon projected yields for 10-year treasuries in the relevant future periods, plus an estimated risk premium for each utility. See AG Exhibit 1.12 at 1, 2, 4, 5. The Companies have made it clear that they do not wish to rely on recent, actual debt cost information, despite it being the best available information upon which to calculate the costs of long term debt. AG Ex. 4.0 at 68. Rather, the Companies claim that speculative forecasts are the best available information. NS-PGL Ex. 23.0 at 7. The trouble with this approach is that, in the current low-interest rate environment, it is typical for forecasts to forecast interest rates to be initially higher. As the date of the debt issuance nears, it is also typical for those forecasts to be revised downward. An example of this trend is NS's planned May 2013 debt issuance, which originally was projected at a cost rate of 4.75%, but only months later, this forecast was reduced to 4.20%. Similarly, the NS September 2013 issuance was estimated to cost 4.95% but has since been reduced to 4.45%[36]. There are additional, real-world examples taken from the Companies own data that illustrate this trend.[37] The trend reliably demonstrates that, in the current environment, long term debt costs should not be based on forecasted costs far removed from the issuance date. Ratepayers should not be locked into a long-term commitment to pay for overstated debt costs on new issuances, when it is expected that these costs will actually be lower given recent, actual issuances made by these Companies.

The second issue merits Commission attention only if the Companies are allowed to employ a year-end rate base. As explained by AG witness Brosch, the Companies utilize an average accounting method for outstanding monthly debt balances and cost rates. AG Ex. 1.0 at 57-8; see NS-PGL Sched. D-3. If the Companies prevail in their proposed utilization of a year-end rate base, the People recommend utilizing a year-end costing approach to quantify the cost of long-term debt. This is essentially a matter of fairness and consistency. The Companies should not be allowed to quantify rate base at year-end to increase revenue requirements, while ignoring the declining costs of long term debt that would be lower if consistently annualized at year-end. The Companies use of this average monthly accounting method for outstanding bonds is grossly inconsistent with the Companies' advocacy for use of a year-end rate base.[38] Further compounding the Companies already overstated revenue requirements; the Companies have made it clear that they expect to refinance older higher cost bonds at currently lower market interest rates during the 2013 test year. AG Ex. 4.0 at 68. Nonetheless, they have elected to use an average Long Term Debt cost rate calculation approach that is inconsistent with their year-end rate base.

[36] Until PGL filed its surrebuttal testimony, PGL listed a "New Issue" of $100 million of long term debt on 11/01/12 recognizing an estimated cost rate of 4.03%; however, this debt issuance actually occurred at a final coupon rate of 3.98%. PGL appears to have accepted the lower final coupon rate as Mr. Brosch recommended in his testimony. AG Ex. 4.0 at 66.

[37] For PGL, a second "New Issue" of $200 million of long term debt on 9/01/13 at an estimated cost rate of 4.03% is recognized, at an estimated coupon rate of 4.45%. This cost rate is higher than current capital market cost rates. For NS, a "New Issue" of $55 million of long term debt on 5/01/13 at an estimated cost rate of 4.20% is recognized. This cost rate is higher than current capital market cost rates.

[38] For other previously stated reasons, the People find the Companies' use of a year-end rate base objectionable and acknowledge only that the Companies advocate for the use of the year-end rate base.

The result is that ratepayers are denied full participation in the annual interest savings resulting from such refinancing.

Commission Analysis and Conclusion

The Commission agrees with the Utilities-Staff agreement that the long-term debt cost for Peoples Gas should be adjusted to incorporate the lower refinanced cost of its Series KK bonds. The refinancing was completed in April 2013 and therefore should be reflected in Peoples Gas' 2013 rates. The results of this refinancing were presented in a post-hearing motion filed by the Utilities on April 17, 2013. The result of the lower interest rate for this long-term debt is to reduce the overall cost for North Shore's long-term debt from 4.64% to 4.53% and the lower interest rate for the long term debt is to reduce the overall cost for Peoples' long term debt from 4.47% to 4.37%. There was no objection to this additional information being admitted into the record.

The Commission agrees with the Utilities that setting long-term debt costs on an annual average basis is more appropriate in this case than an end of year measure. The annual average approach is authorized by Commission rule and it is consistent with the manner in which the Utilities' agreed capital structure balances have been calculated. Thus, the rates will more accurately reflect their forecasted costs if the Utilities' annual average long-term debt costs is used.

E. Cost of Common Equity

Utilities

1. Overview

Utilities' Overall Position

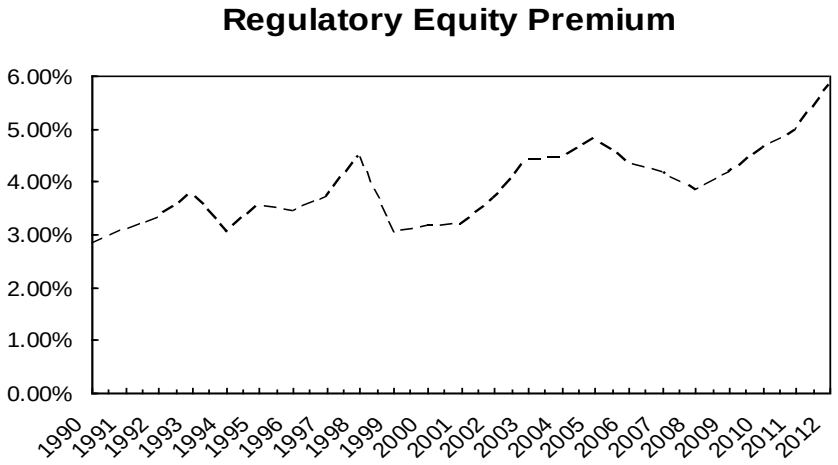
Because the Utilities' common stock is not publicly traded, their cost of equity must be estimated using capital market and financial data relied on by investors to assess the relative risk of other "distribution-only" utilities. Utilities witness Mr. Moul presented three "market" measures of the Utilities' return on equity ("ROE") based on a proxy group of natural gas utilities. Mr. Moul applied the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM") and the Risk Premium model. After initially recommending a higher ROE, on surrebuttal, Mr. Moul presented a compromise position on behalf of the Utilities that was intended to reduce the number of disputed issues in the case. The model results that followed from that compromise proposal are as follows:

Model	Equity Cost
DCF	8.98%
CAPM	10.03%
Risk Premium	11.00%
Average	10.00%

NS-PGL Ex. 39.0 at 1-2.

The Utilities assert that Mr. Moul's equity model results as well as general market information about the prevailing cost of utility equity support a modest increase of their current 9.45% ROE to 10.00%. Such an ROE, the Utilities argue, would comport with the 9.94% average ROE for natural gas utilities in 2011-2012. It would also be consistent with 10.30% average forecasted return in 2013 for the "Delivery Group," the proxy group of electric and natural gas distribution-only companies that Mr. Moul and Staff witness Mr. McNally used to estimate the Utilities' cost of equity for the test year. NS-PGL Init. Br. at 130-131.

In response to Mr. McNally's argument that the Utilities' cost of equity should be reduced to reflect historically low interest rates, Mr. Moul showed that the "equity risk premium," the difference in cost between A-rated utility bonds and recent utility authorized ROEs, has increased dramatically since the start of the Great Recession in 2008:



NS-PGL Ex. 39.0 at 3-4.

The current average utility equity risk premium stands at 581 basis points. If that premium is applied to the Utilities' undisputed long-term debt costs in this case, it generates a 10.28% ROE for Peoples Gas and 10.44% for North Shore. *Id.* at 4. Thus, the Utilities assert, their requested ROE of 10.00% is well within the market ballpark of utility returns.

The Utilities find "confounding" Staff's continued refusal to even consider ROEs authorized for other utilities in 2011-2012 on the grounds that individual ROEs cannot be compared without knowing the underlying details. NS-PGL Init. Br. at 147. They note that such returns comprise a large sample and in other contexts Staff acknowledges that the use of samples "mitigates" the "measurement error" that might occur if one relied on a single piece of data. Staff Exs. 5.0 at 28 & 15.0 at 14. The Utilities reason that the same principle applies to the large samples of recent ROEs (146 observations in all) that are readily available to investors, analysts and this Commission. NS-PGL Br. at 148. Furthermore, the evidence shows that Mr. McNally's speculative concerns about comparability issues is unfounded, and that the similarity of the underlying conditions make these sample-based data quite comparable to the Delivery Group. NS-PGL Ex. 39.0 at 2-3. The Utilities also point out that AG witness Brosch relied solely on a sample of recent utility ROEs to arrive at his opinion that the Utilities' ROE should remain at 9.45%, a "recommendation" that CUB-City argued was "fully justified." AG Ex. 1.0 at 61.

CUB-City join Staff in arguing that the Commission should not consider recent ROEs, claiming that it has refused to do so in prior rate cases. CUB-City Init. Br. at 57. But according to the Utilities, they are not asking the Commission to "determine" ROE by comparison to other ROEs or to set their ROE at the average of other ROEs. Rather, they ask the Commission to consider other ROEs and other general market information for context when it assesses the credibility of the parties' various ROE positions. Based on this test, the Utilities' 10.00% ROE is in the ballpark. Staff's 9.06% is far too low, indicating that it is the product of error, bias or both. NS-PGL Reply Br. at 132.

The Utilities argue that all of these considerations support an increase of the Utilities' cost of equity to 10.00%.

Staff

Three parties presented estimates of the Companies' costs of common equity: the Companies, the AG, and Staff. The Companies initially estimated North Shore's and Peoples Gas's return on equity ("ROE") to be 10.75%, but subsequently updated their estimate to 10.00%. NS Ex. 3.0 at 47; PGL Ex. 3.0 at 47; NS-PGL Ex. 39.0 at 1-2. AG witness Brosch did not perform an analysis of the Companies' cost of common equity, but rather, proposes to use the same 9.45% cost of common equity authorized in the Companies' last rate setting proceeding. AG Ex. 1.0 at 61; AG Ex. 4.1, Sched. D; AG Ex. 4.2, Sched. D. Staff estimated North Shore's and Peoples Gas's ROE to be 9.06%. Staff Ex. 5.0, Sched. 5.01.

Staff's Analysis

Staff witness Michael McNally estimated Peoples Gas's and North Shore's investor-required rate of return on common equity to be 9.06%. Staff Ex. 5.0, Sched. 5.01. Mr. McNally measured the investor-required rate of return on common equity with discounted cash flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses. Mr. McNally applied those models to a sample of thirteen natural gas and electric delivery companies ("Delivery Group"). The Delivery Group was the same sample used by Company witness Moul. Staff Ex. 5.0 at 13. To select that sample, Mr. Moul started with the universe of gas utilities categorized in Value Line's "Natural Gas Utility" group, which consists of eleven companies. He then eliminated two companies due to the different operations in which those companies engage. The nine remaining companies are: AGL Resources, Atmos Energy, Laclede Group, New Jersey Resources, Northwest Natural Gas, Piedmont Natural Gas, South Jersey Industries, Southwest Gas, and WGL Holdings. To those nine he added four electric utility holding companies in Value Line's "Electric Utility (East)" industry group whose utility subsidiaries are engaged principally in the delivery of gas and electricity: Consolidated Edison, Northeast Utilities, PEPCO Holdings, and UIL Holdings. Together, those thirteen companies compose the Delivery Group. NS Ex. 3.0 at 4-5; PGL Ex. 3.0 at 4-5.

The Companies devote a great deal of their testimony regarding Staff's ROE analysis to the proposition that Staff's results are "woefully inadequate." NS-PGL Ex. 24.0 Rev. at 1-5. However, although Mr. Moul criticizes certain aspects of Mr. McNally's analysis, which Staff addresses below, he never demonstrates how the alleged errors he points to cause Mr. McNally to understate the ROE. In fact, Staff demonstrated that one of Mr. Moul's criticisms of Mr. McNally's analysis – that his use of a constant growth DCF model was chosen to produce a lower result – is factually incorrect, as Mr. McNally's use of a constant growth DCF actually produced a <u>higher</u> result than if a non-constant growth DCF had been used. Staff Ex. 15.0 at 12. Thus, the conclusion that Staff's results are too low cannot be drawn from the specific criticisms Mr. Moul alleges. The reality is, Staff's lower results are not due to any alleged errors by Staff, but are simply the results indicated by investor behavior, given the market environment. Indeed, Mr. Moul's results would have been similar to Staff's if he had not inappropriately adjusted his DCF and CAPM results and used an outdated, empirically unsupported, historical risk premium model. Both the adjustments he applied and his use of a risk premium model are theoretically unsound and, accordingly, have been repeatedly rejected in prior Commission proceedings. When those factors are removed, the average of the results of Mr. Moul's CAPM and DCF analyses for the Delivery Group and those of Mr. McNally's CAPM and DCF analyses differ by a mere 22 basis points, <u>with Mr. Moul's results being lower than Mr. McNally's</u>. Staff Ex. 15.0 at 8.

Mr. Moul argues that Staff's cost of common equity recommendation is "simply not representative of the returns investors can earn on other investments of comparable risk." NS-PGL 24.0 Rev. at 2. This criticism is unsubstantiated and clearly wrong. First, his argument is based on three inapt comparisons: (1) a comparison to previously

authorized ROEs; (2) a comparison to his own upwardly adjusted ROE estimates; and (3) a comparison to Value Line forecasts of book value returns. The first approach has been fully discredited by Staff and rejected by the Commission in numerous prior rate setting proceedings. Mr. Moul's comparisons to previously awarded ROEs are meaningless, as not only do they represent authorized returns for *other* companies, in *other* jurisdictions, at *other* times during *other* market environments, but the facts needed to assess the degree of comparability, including such critical aspects as the relative risk of the utilities involved and the market environment in which those decisions were made, are entirely unknown. Without such data, those comparisons are useless. Staff Ex. 15.0 at 8-9. Likewise, the second approach is uninformative because it depends on the proposition that Mr. Moul's upwardly adjusted estimates of the cost of common equity are accurate.[39] The third approach is also fatally flawed because it relies on forecasts of book earnings that are not only speculative, but are not comparable to the investor-required return. It is difficult enough to estimate the *current* investor-required return when actual data is available, but to attempt to project what investors will demand at some point in the *future* is pure speculation. Worse yet, the Value Line projected returns on book equity that Mr. Moul cites are entirely unaffected by changes in the investor-required rate of return and, thus, cannot be used as a substitute benchmark for the investor-required return. In fact, investors cannot invest at (and earn a return on) book value, but must pay market value. Mr. Moul's own use of CAPM and DCF analyses to estimate the investor-require return recognizes as much, as those models are based on market value stock prices. Thus, those Value Line book value returns are clearly not returns investors can earn on other investments of comparable risk, rendering them invalid benchmarks for the investor-required return. Staff Ex. 15.0 at 10-11.

Second, as Mr. McNally pointed out, given the context of the current interest rate environment, with interest rates at the lowest they have been in over 20 years and consistently trending lower, Mr. McNally's cost of common equity estimate <u>is</u> what a rational investor would expect. Staff Ex. 15.0 at 9. In response, Mr. Moul notes that the other component of the authorized return on equity, the equity risk premium,[40] has risen during that period, which he suggests means a higher authorized return is warranted. NS-PGL Ex. 39.0 at 3-4. But Mr. Moul's testimony misleadingly divulges only part of the story; the rest of the story, which is revealed in his work paper, demonstrates his claim to be false. That work paper shows that the falling interest rates Mr. McNally cited more than offset the rising risk premium Mr. Moul cited. That is, contrary to Mr. Moul's implication, his own work paper explicitly shows that, along with the interest rates Mr. McNally cited, authorized returns have been steadily trending downward for over 20 years and are at the lowest they have been in that time. Staff Cross Ex. 8.

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[39] An estimate cannot be a useful benchmark of the accuracy of a different estimate until the accuracy of that "benchmark" estimate has been established. One could as easily argue that Mr. McNally's estimates of the cost of common equity demonstrate that Mr. Moul's estimates are too high, but Staff does not fall into this illogical dead end. Rather, as will be detailed later, Staff establishes the inaccuracy of Mr. Moul's cost of common equity estimates through an analysis of the tortured models and methodologies from which they were elicited.

[40] The market-required rate of return is composed of two components: the nominal risk-free interest rate and the equity risk premium. (Staff Ex. 5.0, p. 18)

CUB-City

In their testimony and exhibits, CUB-City used the return on equity approved by the Commission in the Companies' last rate case. CUB-City Ex. 1.0 at 9. The same return level was recommended by AG witness Michael Brosch. AG Ex. 1.0 at 61; AG Ex. 4.0, 69-70. After reviewing the Companies' evidence for an increased cost of equity, Mr. Brosch recommended that the Commission use the return on equity it determined to be reasonable in the Companies' last rate case -- 9.45%. *Id.* CUB-City aver that recommendation was fully justified by (a) the flawed evidence (discussed below) that the Companies presented to support their proposed increase in return level and (b) the Commission's thorough investigation of the Companies' requirements in an order issued about only one year ago. CUB-City note that Mr. Brosch did not conduct an independent review and analysis of current market factors, but observed that the Commission's determination of last year is consistent with return determinations for other gas distribution utilities. AG Ex. 4.0 at 69-70.

However, CUB-City explain, Staff expert Michael McNally did conduct full, current cost of equity analyses for the Companies. *See* Staff Ex. 5.0 at 13. Mr. McNally estimates the Companies' cost of equity at 9.06%. *Id.* at 13. The Commission's recent decision considered an almost identical, flawed presentation from the Companies' expert, Paul Moul. CUB-City found the combined effects of that Commission analysis, coupled with Staff's cost of equity analysis and Staff's critique of the Companies' analyses very persuasive. On consideration of the entire record, including the testimony of all witnesses on this issue, CUB-City support the recommendation of Staff expert McNally.

<u>The Companies' Flawed Analytical Methods Have Been Thoroughly Reviewed and Rejected by the Commission</u>

CUB-City aver that Mr. Moul's testimony presents no new substantive methodologies or arguments that the Commission has not reviewed in detail in past cases. *Compare* NS-PGL Ex.3.0 at 3 (DCF, RP and CAPM models), 4 (two proxy groups), 5 (DCF leverage adjustment), 42 (CAPM size adjustment) and Order, Docket No. 11-0280/0281, Jan 10, 2012 at 112 (DCF, RP and CAPM models), 114 (two proxy groups), 114 (DCF leverage adjustment), 115 (CAPM size adjustment). CUB-City further state that the Companies present no compelling evidence warranting a change in the Commission's traditional approach to cost of equity determinations. As to the specific methodologies of Mr. Moul's analyses, and his regularly rejected adjustments, CUB-City argue the Commission's past policy decisions should control. As noted below, other elements of the Companies' recommendation are as often undermined as supported by the Companies' testimony.

<u>Risk Premium Model</u>. First, CUB-City consider the Companies' use of a Risk Premium estimation model. CUB-City note that just one year ago, the Commission rejected the Companies' use of this analytical approach, commenting that it had been

"outright rejected in past decisions." Order, Dkt. 11-0281/0282. In the case before that, the Commission had ordered:

> The Commission will not consider the results of the Utilities Risk Premium model that only the Companies have employed. We have repeatedly rejected this model as a valid basis on which to set return on equity. Our view remains unchanged. Order, 09-0166/0167, Jan 21, 2010 at 128.

CUB-City explain that, in the face of clear direction from the Commission, the Companies have again presented a Risk Premium analysis. In this context, CUB-City aver the strategic purpose of that analysis is clear. CUB-City point out that by adding more high ROE estimates to an anticipated averaging by the Commission (*see, e.g.,* Order, Dkt. 11-0281/0282 at 153), the resulting average can be raised, the effect of lower estimates diluted, and the apparent ceiling on reasonable returns elevated.

Combination Proxy Group. Second, CUB-City consider the supplemental proxy group used to develop the Companies' recommended equity return, which undeniably has different risk characteristics from the Companies', as that group contains both electric and gas firms. As Staff expert McNally explained:

> It was not necessary to employ his Combination Group, since Delivery Group is a sufficiently large sample that represents the risk of the Companies well, as Mr. Moul himself concluded. Moreover, the Combination Group is less like the Companies in terms of operations than is the Delivery Group, as Mr. Moul noted in his direct testimony.

Staff Ex. 15 at 11. (emphasis added).

However, CUB-City aver, the mathematical strategy noted above also may account for the introduction of this unnecessary additional proxy group. Staff Ex. 15 at 11. CUB-City state that by including a Risk Premium analysis and doubling the number of proxy groups, Mr. Moul injected four additional, high estimates into his averaging process (at equal weight), raising the resulting average. PGL Ex. 3.0 at 7. CUB-City note that simply eliminating Mr. Moul's extra estimates,[41] without correcting any other errors, lowers his average by almost 100 basis points. Similarly, their inclusion in a Commission's determination would benefit the Companies.

CUB-City argue that the opportunities for manipulation inherent in adding extra cost of equity estimates to the debate are clear. They are further revealed by the alacrity with which the Companies discarded that entire set of estimates, to fashion its compromise recommendation. NS-PGL Ex. 39 at 1-2.

[41] That is, using only Mr. Moul's Gas Group and his results for the Commission's preferred analyses (DCF and CAPM) lowers the calculated average to 10.08% [(8.98% + 11.17%)/2].

Leverage. Third, CUB-City point out that Mr. Moul's regularly rejected leverage adjustment is a significant factor in inflating his DCF estimates of the market required return. CUB-City note that the Commission has already expressed both its understanding of the proposal and its analytical rejection of the adjustment. Despite Mr. Moul's recurring efforts to recast his proposal using different terms (*see, e.g.*, PGL Ex. 3 at 26), the Commission long ago grasped the reality of the adjustment.

> The Utilities adjust both their DCF and CAPM analyses so that the authorized return applied to the Utilities' book value capital structures will, in their view, correctly represent investor-required return. They maintain that the costs of equity produced by the financial models are based on the market value capitalizations of the utility sample. They further assert that the proxy group's market value capitalizations contain more equity and less financial risk (debt) than its book value capitalizations used for ratemaking purposes, which contain less equity and more financial risk. The Utilities argue that when a market-based cost of equity is applied to a book value capital structure there is a mismatch in financial risks and under-recovery of allowed (*sic*) the utility's allowed return. Order, Docket No. 07-0241/0242, Feb 5, 2008 at 95.

CUB-City note that the Commission was equally clear in stating the reason such an adjustment is unlawful, as well as inappropriate.

> In the Commission's judgment, the book value capital structure reflects the amount of capital a utility actually utilizes to finance the acquisition of assets, including those assets used to provide utility service. In establishing the overall or weighted average cost of capital, the proportion of common equity, based on the book value capital structure, is multiplied by market-required return on common equity. The Commission has used this approach in establishing utility rates for at least twenty-five years. . . . Market value is not utilized in this calculation because <u>it</u> typically <u>includes</u> appreciated <u>value</u> (as reflected in stock prices) <u>above the utilities' actual capital investments</u>.[42] Order, Dkt. 07-0241/0242, Feb 5, 2008 at 95-96 (emphasis added).

The Commission found that "this process is equivalent to applying an unadjusted equity return to the market value of the utility's shares, resulting in an adjustment identical to the one we rejected in the Ameren Order. . . . Again, our practice is to approve a return

[42] Mr. Moul has identified only one regulator that has been convinced to accept this adjustment, while he acknowledges this Commission's repeated rejections of it. NS-PGL Ex. 3.0 at 26.

on a utility's actual investments at book value, not on the appreciated value of its common stock, however calculated and denominated." *Id.*

CUB-City aver that the PUA explicitly denies the Commission authority to allow a utility to earn on more than "only the value of such investment which is both prudently incurred and used and useful in providing service to public utility customers." 220 ILCS 5/9-211. CUB-City maintain that the proposed leverage adjustment would effectively include the stock appreciation enjoyed by market participants in the Companies' rate bases -- even though none of that value is devoted to providing the Companies' utility service. As the Companies concede, "the value of the rate base does not respond to changes in the market value of a utility's securities." NS-PGL Ex. 39.0 at 8. Thus, states CUB-City, the leverage adjustment Mr. Moul proposes would be unlawful under Illinois law.

CUB-City explains the remainder of the Companies' arguments is of no consequence. The Commission cannot artificially increase PGL's rate base. Nor can the Commission use leverage adjustment slight-of-hand to accomplish the same mathematical result by inflating the allowed return above that required by the market.

<u>Other Companies' Returns</u>. Fourth, CUB-City note Mr. Moul's attempts to defend his continuing reliance on returns awarded by various state commissions, at different times, on the basis of unknown evidence, to other utilities that the Companies have not shown to have common risk characteristics. For example, as to the risk effects of Rider VBA, Mr. Moul could assert only that most of the companies in his sample have "<u>some form</u> of RSM [revenue stabilization mechanism] that is <u>intended</u> to accomplish the same <u>result</u> as the Company's decoupling mechanism. PGL Ex. 3.0 at 8. CUB-City maintain that Mr. Moul offers no meaningful evidence of similar effects on risk, speculates that various commissions implemented different RSMs with the same intent, and equates speculated intended results with actual evidence. Mr. Moul suggests that the Commission's requirement for relevant evidence can be set aside -- if he imposes enough adjustments and constraints on his collection of commission determined returns. NS-PGL Ex. 39.0 at 2-3. CUB-City argues that Mr. Moul is wrong.

Constrained by the PUA (220 ILCS 5/9-201, 10-103) and the rules of evidence (IRE 402), CUB-City notes that the Commission has correctly refused to rely on such collections of returns from other jurisdictions. The Commission has explained repeatedly that such data are irrelevant and that reliance on them is unlawful.

> • "[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." Order, Docket No. 07-0241/0242 (Consol.), Feb 5, 2008 at 90.
>
> • "[A]lthough the notion that the Utilities should enjoy at least an average ROE is superficially seductive, it is an unworkable and

improper basis for determining utility returns." Order, Docket No. 07-0241/0242 (Consol.), Feb 5, 2008 at 90.

• "In re Commonwealth Edison Company, ICC Docket No. 05-0597, Order at 154 (July 26, 2006). The Commission is completely uninformed as to the decisions from other these other jurisdictions where we have no evidence that circumstances are comparable. Such comparisons are not relevant." Order, Docket No. 11-0280/0281 (cons.), Jan 10 2012 at 137.

Mr. Moul also claims validation of his use of multiple commission ROE determinations in Staff's use of multiple estimates of the CAPM beta. NS-PGL Ex. 39.0 at 3. However, CUB-City note that Staff's estimates all measure the same thing, but Mr. Moul's do not. CUB-City aver that even Mr. Moul does not argue that the cost of equity is the same for every firm, or that his analysis looks at different estimates of a single unique cost. In contrast, the risk based returns for more than 100 different firms measure something that is unique to each firm.

Size. Finally, CUB-City note that the Companies (again) propose an adjustment for utility size. CUB-City point out that the Companies' size adjustment for their CAPM analysis has been as poorly regarded by the Commission as their leverage adjustment: "As we have in other cases, the Commission finds this [size] adjustment to be unwarranted." Order, Docket No. 11-0280/0281, Jan 10, 2012 at 152; *also see* Order, Docket No. 03-0403, Apr 13, 2004 at 43 ("[The utility] is a wholly-owned subsidiary within a much larger organization, and in that sense is distinguishable from an independent utility of the same size . . . ."). CUB-City note that the Companies have not identified a single case where this Commission has accepted such an adjustment.

CUB-City explain these improper adjustments and flawed methods have a dramatic effect on the results of the analyses the Companies present. The repeated use of discredited methodologies unavoidably calls into question the reliability of other aspects of the analyses. Ultimately, CUB-City find, the corrections discussed would bring Mr. Moul's estimates closer to the recommendations of the Staff.

CUB-City aver that the evidence in this case includes full DCF and CAPM analyses from the Staff's expert as well as incisive critiques of the Companies' analyses. CUB-City note that Mr. Moul's criticism of McNally's analyses rests principally on Mr. McNally's rejection of the Combination Group results discussed above. NS-PGL Ex. 24.0 at 5. Yet, Mr. Moul also discarded those results in his final recommendation. CUB-City aver that Mr. Moul's other criticisms (like his adjustments) repeat claims that have not been accepted in past cases. Staff's analyses fill the gaps created by the flaws in the Companies' studies. CUB-City maintain that the record as a whole supports the Staff's recommended cost of equity, and CUB-City recommend its use in this case.

CUB-City recommend that if Staff's recommended ROE is not accepted – though it should be -- the ROE the Commission found reasonable in the Companies' most

recent rate case should not be disturbed. CUB-City aver that the failure of the Companies to establish that a higher level of return is warranted leaves the current ROE as the maximum reasonable ROE. That is the level recommended in testimony by AG witness Brosch. AG Ex. 1.0 at 61; AG Ex. 4.0 at 69-70. CUB-City note that despite Mr. Moul's mis-characterization of that recommendation (NS-PGL Ex. 24.0 at 2), the Commission made its determination on the basis of evidence independent of the actions of other utility regulatory commissions. Order, Docket No. 11-0280/0281 (cons.), Jan 10 2012 at 137. CUB-City argues that the Commission's determination did not rely improperly on other commission awards, nor does the Brosch recommendation, and nothing higher is justified.

2. Proxy Group Analysis

Utilities

Because the Utilities' stock is not publicly traded, their cost of equity must be estimated using mathematical models applied to a proxy group of publicly-traded companies with investment risk similar to that of the Utilities. NS Ex. 3.0 at 4. Mr. Moul based his 10.00% ROE recommendation on model runs using a proxy group of publicly traded electric and natural gas distribution-only utilities referred to in the record as the "Delivery Group." *Id.* at 4-6.[43] Mr. McNally, the only other witness to present a cost of equity based on the market models, found the Delivery Group to "provide reasonable proxies for the risk of North Shore and Peoples Gas" and used it for his models. Staff Ex. 5.0 at 13.

3. DCF

Utilities

The DCF model expresses the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return, which for common stock is the dividend yield plus future price growth. NS Ex. 3.0 at 15. Mr. Moul used a six-month average dividend yield for the Delivery Group, adjusted by three generally accepted methods to reflect investors' expected cash flows, and averaging the three adjusted values. *Id*. at 16. For the investor-expected growth rate, Mr. Moul evaluated an array of historical and forecast growth data from sources that are publicly available to, and relied upon by, investors and analysts. *Id*. at 20-21. He focused on forecasts of earnings per share growth because empirical evidence supports it and because that they are most relevant to investors' total return expectations. *Id*. at 22-23. He selected 4.50%, the approximate mid-point for the Delivery Group. *Id*. at 24. Mr. Moul then applied a financial leverage adjustment to his DCF results because they are based on market prices of the Gas Group's stock, which imply a capital structure with more equity and less financial risk, but are applied to utility book values, which imply a

[43] Mr. Moul initially included in his analysis the results from an additional proxy group, a "Combination Group" of electric and natural gas utilities. NS Ex. 3.0 at 6. As part of the Utilities' compromise position on ROE, they are not including the ROE results for this proxy group in this case. NS-PGL Ex. 39.0 at 2.

capital structure with less equity and more financial risk. *Id*. at 24-30. Mr. Moul's leverage-adjusted DCF result for the Delivery Group was 8.98%. *Id.* at 30. By comparison, Mr. McNally presented a higher DCF result of 9.32% based on forecasted growth rates and stock prices for the Delivery Group on a single day, November 9, 2012. Staff Ex. 5.0 at 14-18.

There are three disputed issues between the Utilities and Staff with respect to DCF methodology: (1) Staff's "lower of" approach to the model, (2) Staff's reliance on historical spot data, and (3) Mr. Moul's leverage adjustment. The Utilities' arguments on each of these issues are presented in turn.

Staff's "Lower Of" Approach Introduces Bias

According to the Utilities, over their last several rate cases Staff has used two different versions of the DCF model depending on certain circumstances. When growth forecasts for the proxy group are at or below Gross Domestic Product (GDP) growth forecasts, Staff uses the "constant growth" version of the model, in which the same growth rate is assumed into the future. When growth rate forecasts for the proxy group are higher than those for GDP, Staff uses a "non-constant growth" version, where near-term and long-term growth rates are assumed, to generate a lower ROE than the constant growth version would generate. Mr. Moul finds this "lower of" approach to be biased against the Utilities. NS-PGL Ex. 24 at 9. The Utilities point out that in their second-to-last rate case, the Commission rejected "Staff's position that the non-constant growth form of the model must be used any time it can be claimed that analyst growth rates are not sustainable." *Peoples Gas 2009* Order at 125.

In this case, Staff's witness used the constant growth model after finding the Delivery Group's growth rate of 4.83% comparable to GDP growth rate of 4.3-4.9%. Staff Ex. 5.0 at 15. After the Utilities raised their concern about Staff's "lower of" approach, Staff's witness claimed that had he used the non-constant growth version of the model he would have used a lower long-term growth rate of 3.35%. Staff Ex. 15.0 at 12. The Utilities argue that this is inconsistent with the position of Staff's witness on direct that the 4.83% growth rate for the Delivery Group was "reasonably sustainable," supporting his use of the constant growth version of the DCF model. The Utilities conclude that this only confirms their concerns about bias underlying Staff's methodology. NS-PGL Init. Br. at 144.

Staff's Reliance on Historical Spot Data Is Unjustified

The Commission has in two of the Utilities' recent rate cases admonished Staff that its reliance on data taken from a single day in the past – here, November 9, 2012 – to run its cost of equity models will not be accepted without proof that the results are representative of the Utilities' cost of equity in the test year. In the Utilities' 2007 rate case, the Commission found that "Staff's single data point for use in its DCF is unsatisfactory for the intended purpose in these dockets" because short-term vagaries of the market can affect stock prices and yields on a single trading day." *Peoples Gas*

2007 Order at 92. Likewise, in the Utilities' 2009 rate case, the Commission observed that:

> it would useful for the Commission to be told the conditions or financial climate of the spot day and whether any of these might cause material market inefficiencies. And, more importantly, we would expect the expert to be acutely attuned to that environment in making a selection. The choice of a spot day may be random or informed and we prefer some combination of both. While the Commission has traditionally accepted spot day analysis, we are not absolutely committed to this approach.

Peoples Gas 2009 Order at 125-126.

The Utilities argue in this case that Staff has once again failed to demonstrate the reliability of its model results based on historical spot data. The Utilities observe that Staff opposes the consideration of forecast data because forecasts are often imprecise in hindsight, but Staff has not shown that historical spot data are better predictors than forecasts. In particular, Staff did not provide evidence that its spot data were immune to short-term market inefficiencies or other measurement errors. The fact that Staff repeated its analysis during a single week in November 2012 does not address this shortcoming. According to the Utilities, "At most, all that Mr. McNally's cost of equity measurements demonstrate with any confidence is what the Utilities' market cost of equity was in one week in November 2012. They do not answer, and therefore are not relevant to, the issue at hand: what the Utilities' cost of equity will be during the 2013 test year." NS-PGL Init. Br. at 141 (emphasis in original). As a result, the Utilities assert, Staff's DCF and CAPM results are not reliable. In particular, they point to the extreme variance in Staff's DCF results for the individual Delivery Group companies, from 6.52% (clearly too low) to 11.75% (clearly too high). *See* Staff Ex. 5.0, Sched. 5.07.

<u>Mr. Moul's Leverage Adjustment is Methodologically Sound</u>

Mr. Moul applies a "leverage" adjustment to his DCF and CAPM results to correct the mismatch that otherwise occurs when a market-based cost of equity, which is based on the proxy group's average market value capital structure, is applied to the utility's book value capital structure. Currently, the Delivery Group's average market value capital structure has proportionally more equity and less risk than its average book value capital structure. Mr. Moul adjusts the market cost of equity generated by the mathematical models so that the equity cost reflects the lower amount of equity and higher risk of the book value capital structure. NS Ex. 3.0 at 24-30; NS-PGL Ex. 24.0 REV at 14-16. If the adjustment is not made, the market cost of equity applied to the book value capital structure will prohibit the utility from earning the full return implied by the market cost of equity. NS-PGL Reply Br. at 128-129.

The Utilities refute each of the arguments raised by Staff and CUB-City as to why the Commission should reject Mr. Moul's leverage adjustment. First, the Utilities deny that the adjustment constitutes "fair value" ratemaking, which Staff erroneously claims is prohibited by Section 9-210 of the Act. Staff Init. Br. at 88. The Utilities assert that Staff mischaracterizes fair value ratemaking as involving the application of a market ROE to a market value capital structure. The Utilities cite Illinois case law making clear that the fair value concept gives the Commission great latitude in setting the value of a utility's investment, which can include consideration of both original cost and market value. Further, the Utilities point to Commission decisions applying fair value ratemaking in which it considered non-market factors in setting the utility's return. NS-PGL Reply Br. at 125-128.

Second, the Utilities counter CUB-City's claim that the leverage adjustment runs afoul of Section 9-211 of the Act because it would allow the Utilities to over earn. The Utilities point out that with or without the adjustment, their rates remain based on the return of and on the book value of their investment. *Id.* at 128. The adjustment pertains only to the return on that book value and it is necessary to synchronize a market cost of equity to the book value capital structure used for ratemaking. NS-PGL Ex. 24.0 REV at 14-15; NS-PGL Ex. 39.0 at 8.

Third, although it is true that the Commission has declined to adopt the leverage adjustment for general application in its ratemaking proceedings, the Utilities point out that this did not prevent the Commission from considering Mr. Moul's leverage-adjusted ROE of 10.85% in setting the Utilities' ROE in their last rate case. *Peoples Gas 2011* Order at 139.

Staff

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that stock prices embody. The companies in the Delivery Group pay dividends quarterly. Therefore, Mr. McNally applied a quarterly DCF model. Staff Ex. 5.0 at 14.

DCF methodology requires a growth rate that reflects the expectations of investors. Mr. McNally used a constant growth DCF model in which he measured the market-consensus expected growth rates with 3-5 year growth rate forecasts published by Zacks and Reuters. The growth rate estimates were combined with the closing stock prices and dividend data as of November 9, 2012. Based on this growth, stock price, and dividend data, Mr. McNally's DCF estimate of the cost of common equity was 9.32% for the Delivery Group. Staff Ex. 5.0 at 16-18.

Mr. Moul claims that Staff has been inconsistent with its DCF model selection, since Mr. McNally presented a non-constant growth DCF ("NCDCF") in the Companies' 2009 rate case, but presented a constant growth DCF in this proceeding, and accuses Mr. McNally of using a "lower of approach" to selecting a DCF model "to produce a

lower DCF result." NS-PGL Ex. 24.0 Rev. at 9. Putting aside the aspersion, this criticism is both unfounded and patently false. Staff quite obviously did not use a "lower of approach" in selecting a DCF model in order to produce a lower DCF result, as Mr. McNally's use of a constant growth DCF in this proceeding produced a higher result than if he had used the non-constant growth DCF methodology used in 2009. Staff Ex. 15.0 at 12. When confronted with this fact, Mr. Moul responded by arguing about the proper long-term growth rate to apply in an NCDCF. However, whether the proper NCDCF long-term growth rate is 3.35%, calculated consistent with Staff's 2009 methodology, or 4.33%, as calculated by Mr. Moul using a different methodology, both are considerably lower than the 4.83% sample average growth rate Mr. McNally actually used in his constant growth DCF analysis. Thus, Mr. McNally's use of a constant growth DCF in this proceeding would still produce a higher result than if he had used an NCDCF, which plainly disproves Mr. Moul's criticism. Moreover, Mr. McNally's use of a constant growth DCF model is consistent with the fact that Mr. Moul himself used a constant growth DCF in this proceeding. If Mr. Moul truly believed that Mr. McNally erred in not performing a non-constant growth DCF analysis, then Mr. Moul should have performed a non-constant growth DCF analysis himself.

Staff points out that Mr. Moul further claims to verify that Staff's DCF model "is not producing a reliable measure of the cost of equity" by comparing Mr. McNally's DCF result to that of the 28 utilities included in his S&P 500 market return estimate, which averaged 9.73%. NS-PGL Ex. 24.0 Rev. at 10. However, Mr. Moul has presented nothing to demonstrate that the growth rates used in the S&P utilities' estimates are sustainable. In fact, he explicitly acknowledges that the risk, and consequently the cost of common equity, for the S&P utilities would be higher than that of the Delivery Group, stating "the required common equity risk premium for the Delivery Group was 5.50%, which is less than that for the S&P Public Utilities due to differences in the composition of the companies that comprise each group." NS-PGL Ex. 24.0 Rev. at 13. Specifically, he calculates a 6.23% equity risk premium for the S&P Public Utilities. NS Ex. 3.0 at 35; PGL Ex. 3.0 at 36. The 73 basis point difference between that and the 5.50% equity risk premium he calculated for the Delivery Group would suggest a DCF result of 9.00% (9.73% – 0.73% = 9.00%), which is lower than Mr. McNally's DCF result of 9.32%. Thus, Mr. Moul's own risk premium analysis contradicts his conclusion regarding Staff's DCF result.

4. CAPM

Utilities

The CAPM determines an expected rate of return on a security by adding to the "risk-free" rate of return a risk premium that is proportional to the non-diversifiable, or systematic, risk of the security. This model requires three inputs: (1) the risk-free rate of return, (2) a "beta" that measures systematic risk, and (3) the market risk premium. For the risk-free rate of return, Mr. Moul used historical and forecast yields on 20-year Treasury bonds and selected a mid-point of 4.25% based on current forecasts and recent trends. NS Ex. 3.0 at 40; PGL Ex. 3.0 at 39-40. For the beta measurement of systematic risk, he used the average *Value Line* beta for the Gas Group, adjusted using

the Hamada formula to reflect the application of this market-based measurement to the utility's book value capital structure used in ratemaking. NS Ex. 3.0 at 38-39; PGL Ex. 3.0 at 38-39. Mr. Moul developed his market premium of by averaging forecast data from *Value Line* and the S&P 500 Composite and historical data from Ibbotson Associates, all of which are sources routinely used by investors, analysts and academics. NS Ex. 3.0 at 40-42; PGL Ex. 3.0 at 40-42.[44]

In its application of the CAPM, Staff estimates the "systematic" risk measurement, or the "beta," for the proxy group by averaging betas published by one or more analytic firms like Value Line with a "regression" beta developed by Staff. Staff Ex. 5.0 at 24-28. The Utilities argue that this additional beta is irrelevant to a determination of their market equity cost because analysts and investors are unaware of and do not consider the Staff betas. NS-PGL Ex. 24.0 REV at 12. A more serious concern, however, is that in each of the Utilities' last four rate cases since 2007 including this one the Staff betas have always been lower than the Value Line betas. *Id.* Thus, the Utilities conclude, the Staff beta methodology is biased and serves to adjust the published betas downward to the Utilities' detriment. Accordingly, Staff's CAPM cost of equity measurement is unsound and should be rejected.

Staff

According to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Mr. McNally used a one-factor risk premium model, the Capital Asset Pricing Model, to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which cannot be eliminated through portfolio diversification. Staff Ex. 5.0 at 18-19.

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Mr. McNally combined adjusted betas from Value Line, Zacks, and a regression analysis. The Delivery Group's average Value Line, Zacks, and regression beta estimates were 0.67, 0.58, and 0.54, respectively. The Value Line regression employs 259 weekly observations of stock return data regressed against the New York Stock Exchange ("NYSE") Composite Index. Both the regression beta and Zacks betas employ sixty monthly observations; however, while Zacks betas regress stock returns against the S&P 500 Index, the regression beta regresses stock returns against the NYSE Index. Since the Zacks beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as Value Line uses), Mr. McNally averaged the Zacks and regression results to avoid over-weighting monthly return betas. He then

[44] Initially, Mr. Moul also adjusted his CAPM result for the relatively small size of the Gas Group, correcting a tendency of the model to understate the cost of equity of smaller companies. NS Ex. 3.0 at 42-43; PGL Ex. at 42-43. As part of the Utilities' compromise on ROE, they are not pursuing this position in this case. NS-PGL Ex. 39.0 at 2.

averaged that result with the Value Line beta, which produced a beta for the Delivery Group of 0.62. Staff Ex. 5.0 at 24-29. For the risk-free rate parameter, Mr. McNally considered the 0.13% yield on four-week U.S. Treasury bills and the 2.77% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of November 9, 2012. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.3% and 4.9%. Thus, Mr. McNally concluded that the U.S. Treasury bond yield is currently the superior proxy for the long-term risk-free rate. Staff Ex. 5.0 at 19-24. Finally, for the expected rate of return on the market parameter, Mr. McNally conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market equals 12.81%. Staff Ex. 5.0 at 24. Inputting those three parameters into the CAPM, Mr. McNally calculated a cost of common equity estimate of 8.99% for the Delivery Group. Staff Ex. 5.0 at 29.

Mr. Moul claims that Staff has been inconsistent with its DCF model selection, since Mr. McNally presented a non-constant growth DCF ("NCDCF") in the Companies' 2009 rate case, but presented a constant growth DCF in this proceeding, and accuses Mr. McNally of using a "lower of approach" to selecting a DCF model "to produce a lower DCF result." NS-PGL Ex. 24.0 Rev. at 9. Putting aside the aspersion, this criticism is both unfounded and patently false. Staff quite obviously did <u>not</u> use a "lower of approach" in selecting a DCF model in order to produce a lower DCF result, as Mr. McNally's use of a constant growth DCF in this proceeding produced a <u>higher</u> result than if he had used the non-constant growth DCF methodology used in 2009. Staff Ex. 15.0 at 12. When confronted with this fact, Mr. Moul responded by arguing about the proper long-term growth rate to apply in an NCDCF. However, whether the proper NCDCF long-term growth rate is 3.35%, calculated consistent with Staff's 2009 methodology, or 4.33%, as calculated by Mr. Moul using a different methodology, both are <u>considerably lower</u> than the 4.83% sample average growth rate Mr. McNally actually used in his constant growth DCF analysis. Thus, Mr. McNally's use of a constant growth DCF in this proceeding would still produce a <u>higher</u> result than if he had used an NCDCF, which plainly disproves Mr. Moul's criticism. Moreover, Mr. McNally's use of a constant growth DCF model is consistent with the fact that Mr. Moul himself used a constant growth DCF in this proceeding. If Mr. Moul truly believed that Mr. McNally erred in not performing a non-constant growth DCF analysis, then Mr. Moul should have performed a non-constant growth DCF analysis himself.

Mr. Moul further claims to verify that Staff's DCF model "is not producing a reliable measure of the cost of equity" by comparing Mr. McNally's DCF result to that of the 28 utilities included in his S&P 500 market return estimate, which averaged 9.73%. NS-PGL Ex. 24.0 Rev. at 10. However, Mr. Moul has presented nothing to demonstrate that the growth rates used in the S&P utilities' estimates are sustainable. In fact, he explicitly acknowledges that the risk, and consequently the cost of common equity, for the S&P utilities would be higher than that of the Delivery Group, stating "the required common equity risk premium for the Delivery Group was 5.50%, which is less than that for the S&P Public Utilities due to differences in the composition of the companies that comprise each group." NS-PGL Ex. 24.0 Rev. at 13. Specifically, he calculates a 6.23% equity risk premium for the S&P Public Utilities. NS Ex. 3.0 at 35; PGL Ex. 3.0 at

36. The 73 basis point difference between that and the 5.50% equity risk premium he calculated for the Delivery Group would suggest a DCF result of 9.00% (9.73% – 0.73% = 9.00%), which is lower than Mr. McNally's DCF result of 9.32%. Thus, Mr. Moul's own risk premium analysis contradicts his conclusion regarding Staff's DCF result.

5. Risk Premium

Utilities

The Risk Premium model measures the cost of equity by determining the degree to which equity has more risk than corporate debt, and adding that "equity risk premium" to the interest rate on long-term public debt. NS Ex. 3.0 at 31; PGL Ex. 3.0 at 30-31. Mr. Moul estimated a 5.50% prospective yield on A-rated utility bonds based on historical and forecasted yields. NS Ex. 3.0 at 31-33; PGL Ex. 3.0 at 32-33. Mr. Moul determined a risk premium of 5.50% by analyzing results for S&P Public Utilities and then adjusting those results based upon the results of his fundamental risk analysis in comparing the results for the S&P Public Utilities to the Gas Group. NS Ex. 3.0 at 33-35; PGL Ex. 3.0 at 33-35. Mr. Moul's risk premium analysis thus provided a cost of equity of 11.00%. NS Ex. 3.0 at 36-37; PGL Ex. 3.0 36-37.

The Utilities state that Staff's objection to Mr. Moul's Risk Premium approach – its use of historical data makes it "subject to manipulation" – is precisely why the Commission should reject Staff's DCF and CAPM approaches due to their reliance on historical spot data. NS-PGL Reply Br. at 130. Staff's criticism is also an over-simplification. Although Mr. Moul used historical data, he analyzed the data and concluded they were representative of current market conditions. NS-PGL Ex. 24.0 REV at 13-14.

The Utilities also counter Staff's claim that Mr. Moul did not justify his equity risk premium by pointing out that the Utilities are A-rated and Mr. Moul selected a premium below the premium applicable to the S&P Public Utilities in order to account for differences between (1) that large sample that includes diversified energy companies and (2) distribution-only companies. *Id.* at 12-13.

Staff

In determining the equity risk premium, Mr. Moul began with a 6.23% base equity risk premium estimate representing the historical earnings spread between investment grade public utility bonds and the S&P Utilities Index for the periods 1974-2007 and 1979-2007. Mr. Moul adjusted the 6.23% equity risk premium down to 5.50% in recognition of the lower risk of his proxy group in comparison to the S&P Public Utilities Index. He then added the 5.50% equity risk premium to a projected 5.50% long-term, A-rated public utility bond yield estimate, which resulted in a cost of common equity estimate of 11.00%. NS Ex. 3.0 at 31-37; PGL Ex. 3.0 at 32-37.

Mr. Moul's risk premium analysis contains several flaws that undermine the reliability of the resulting estimates. First, Mr. Moul's base equity risk premium estimate

is calculated from outdated data, which is inappropriate. Use of non-current data falsely assumes that market data reverts to a mean, despite the fact that security returns approximate a random walk. Moreover, no true mean exists. Therefore the selection of a measurement period will necessarily be arbitrary, and that arbitrarily selected measurement period will dictate the magnitude of a historical risk premium, as Mr. Moul's testimony demonstrates. For example, had Mr. Moul used the 1966-2007 measurement period, his base equity premium estimate would have been 4.85% rather than 6.23%, which would need to be adjusted downward even farther for the less risky Delivery Group. Thus, while this approach would, at best, only produce an accurate risk premium by sheer chance, it is unquestionably, and incurably, subject to manipulation.

Second, Mr. Moul's measurement periods end in 2007, rendering his estimates extremely outdated, having been superseded by 5 years of new data. Third, Mr. Moul added a risk premium measured from an investment grade bond index to an estimate of A-rated bond yield without providing any support that the two are comparable. Specifically, Mr. Moul provides no support that the public utility bond index has been, and remains, composed of A-rated bonds with similar terms to maturity as reflected in his A-rated bond yield estimate. Both term to maturity and credit rating are important determinants of bond returns. Fourth, Mr. Moul provided no quantitative support for the adjustments he made in deriving his estimate of the equity risk premium for the Delivery Group (5.50%) from the base equity risk premium (6.23%). Staff Ex. 5.0 at 33-34.

Significantly, Mr. Moul presented the exact same approach in the Companies' 2009 rate case. The Commission rejected that analysis, noting "We have repeatedly rejected this model as a valid basis on which to set return on equity. Our view remains unchanged." Order, Docket Nos. 09-0166/09-0167, January 21, 2010, at 128.

6. Effect of Riders UEA and VBA

Utilities

The Utilities oppose Staff's 10-basis-point downward adjustment to their ROE for Rider UEA because, as Staff concedes, a majority of the Delivery Group companies have similar uncollectible expense trackers. NS-PGL Ex. 24.0 REV at 17-18; Staff Ex. 15.0 at 27. Therefore, an adjustment that assumes none of the Delivery Group companies have such trackers would overstate the Delivery Group's risk relative to that of the Utilities.

The Utilities assert that the Commission should increase their market-based equity costs by 10 basis points to reflect the risk that they will lose Rider VBA. NS-PGL Ex. 24.0 REV at 18-19. In the past, the Commission adjusted the Utilities' ROEs downward by 10 basis points to reflect that the Utilities had a decoupling mechanism. *Peoples Gas 2009* Order at 128; *Peoples Gas 2007* Order at 99. However, in the Utilities' last rate case, the Commission removed this adjustment in recognition that all of the Delivery Group companies have similar mechanisms. *Peoples Gas 2011* Order at 140. The situation is now reversed and the Utilities' Rider VBA is under court challenge. In addition, Staff opposes the Utilities' proposal for straight fixed variable

rates if Rider VBA is ruled invalid. Under these circumstances, Staff cannot seriously contend that the Utilities risk is the same as the Delivery Group with respect to decoupling. Because the Utilities have more risk, their ROE should be adjusted upward.

Staff

In his rebuttal testimony, Mr. Moul suggested that a 10-basis point upward adjustment to the Companies' authorized ROE is warranted due to the possibility that Rider VBA may be rejected by the Appellate Court. NS-PGL Ex. 24.0 Rev. at 18-19. Ironically, although this proposal was not introduced until his rebuttal testimony, it is premature on three counts. First, it assumes that Rider VBA, which apparently both the Commission and the Companies believe is valid, will be ruled invalid. Thus, his proposal would institute a very certain increase in rates based on a very uncertain legal outcome. Second, even if Rider VBA is eventually overturned, no one knows when that might occur. Thus, his proposal would produce higher rates beginning in July of this year, based on a ruling that may be not be made for quite some time after that. Third, his proposal assumes the Companies' request for straight fixed variable rates, should Rider VBA be overturned, will be rejected by the Commission. This proposal would largely mitigate the effects on the Companies' risk if Rider VBA is ultimately overturned. Given that the Companies' request for straight fixed variable rates is still at issue in this proceeding, to assume it will be rejected is premature. Staff Ex. 15.0 at 28.

According to Staff, Mr. Moul argues that bad debt trackers for the Companies in the Delivery Group render the Rider UEA adjustment that has been made in the Companies' last two rate cases unwarranted. NS-PGL Ex. 24.0 Rev. at 17-18. However, Mr. Moul does not provide any data regarding the percentage of the revenues affected by bad debt trackers for the sample companies that have them. Many utilities have other operations or operate in multiple states that provide no bad debt recovery mechanisms. For example, while Mr. Moul lists Atmos Energy ("Atmos") among the sample companies that benefit from bad debt trackers, Atmos also has gas supply operations in Iowa, Missouri, Louisiana, Mississippi, and Georgia, which currently do not offer bad debt recovery mechanisms. In addition, Atmos has other business segments including pipeline and energy market services that would not benefit from bad debt trackers. Thus, we do not know the magnitude of the influence bad debt trackers have on the risk of the sample companies that have them, but clearly it is less for some of them than it is for the Companies. Moreover, by Mr. Moul's own findings, approximately 40% of the Delivery Group companies have no bad debt trackers at all. Therefore, it is clear that the Delivery Group companies do not enjoy the risk-reducing effects of bad debt recovery mechanisms to the extent that the Companies do and, thus, a downward adjustment to the Companies' authorized rate of return on common equity is still necessary. Staff Ex. 15.0 at 27. To estimate the cost of common equity for the Companies, Mr. McNally adjusted the Delivery Group's investor-required rate of return downward 10 basis points to reflect the reduction in risk associated with Rider UEA, which was authorized in the Companies' last rate case with the same 10 basis point adjustment.

7. Commission Analysis and Conclusions

a. The Context

Traditionally, the Commission has established rates of return on common equity for utilities by employing mathematical models designed to quantify the likely cost of attracting capital investment during the time rates are expected to be in effect. In virtually all cases, we have relied on the DCF and CAPM models. The arguments presented in this case do not present a reason to deviate from this position.

While we adhere to the position that the Commission does not base utility returns on those approved for other utilities, in Illinois or elsewhere, we do agree that we have should consider how our decisions will be perceived by the financial markets and what impact those perceptions might have on the Utilities, and thus, ultimately their customers. To this end, the Commission will consider general market conditions and trends because this information influences the decisions that investors make in the market. This information is relevant to our ROE decisions because we estimate what investors demand and that requires consideration of the full array of information that investors consider when they effectively set the real cost of capital for a utility. *See Illinois Bell Tel. Co.,* ICC Docket Nos. 92-0448, 93-0239 (Cons.) (Order Oct. 11, 1994) at 103.

The Commission believes it is important to be apprised of current market conditions because our decisions affect at least in part the capital costs that the market sets for the Utilities, in particular through the credit rating agencies' evaluation of regulation quality and direction. The Commission believes it would be improper to ignore altogether the potential market reactions to our cost of capital decisions.

Based on the record, the Commission recognizes that the average of recent ROEs authorized for natural gas utilities is 9.94%. NS-PGL Init. Br. at 130-131. The Commission also notes that A-rated utility equity risk premiums have recently increased significantly as interest rates remain at historic lows. NS-PGL Ex. 39 at 3-4. These general market data provide relevant comparative information as we assess the parties' various ROE provisions. They do not, however, replace our analysis of the Utilities' specific cost of equity using the traditional tools at our disposal, to which we now turn.

b. The DCF Model

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that stock prices embody. In reviewing the results from the DCF model as performed by the Utilities and Staff, the Commission finds that both approaches reflects bias in its choice between the constant and non-constant versions of the model. The Commission further finds that both have some validity in estimating a reliable estimate of the Utilities' cost of equity.

Although we acknowledge that analysts might disagree as to different variants and ways in which a model might be constructed, we find both Staff's and the Companies' analyses of the DCF methodology to provide some validity. Consistent with a compromise position, we will consider an average of Staff's and the Utilities' DCF result for the Delivery Group only. Mr. Moul's DCF result for the Delivery Group was 8.98%.

Staff's DCF methodology shows that a growth rate that reflects the expectations of investors. The companies in the Delivery Group pay dividends quarterly. Therefore, Mr. McNally applied a quarterly DCF model. Mr. McNally used a constant growth DCF model in which he measured the market-consensus expected growth rates with 3-5 year growth rate forecasts published by Zacks and Reuters. The growth rate estimates were combined with the closing stock prices and dividend data as of November 9, 2012. Based on this growth, stock price, and dividend data, Mr. McNally's DCF estimate of the cost of common equity was 9.32% for the Delivery Group.

The Commission does not endorse every input to or every aspect of the DCF analyses performed by the Utilities or by Staff. Nevertheless, for purposes of this proceeding, the Commission finds that each provides useful input in estimating the market required return on common equity. The Commission used the average of the Utilities and Staff's formulas and determined the ROE of the Delivery Group would be 9.15% under the DCF methodology.

c. The CAPM Model

The CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market.

Utilities' witness, Mr. Moul used historical and forecast yields on 20-year Treasury bonds and selected a mid-point of 4.25% based on current forecasts and recent trends. NS Ex. 3.0 at 40; PGL Ex. 3.0 at 39-40. For the beta measurement of systematic risk, he used the average *Value Line* beta for the Gas Group, adjusted using the Hamada formula to reflect the application of this market-based measurement to the utility's book value capital structure used in ratemaking. NS Ex. 3.0 at 38-39; PGL Ex. 3.0 at 38-39. Mr. Moul developed his market premium of by averaging forecast data from *Value Line* and the S&P 500 Composite and historical data from Ibbotson Associates, all of which are sources routinely used by investors, analysts and academics.

Staff's witness, Mr. McNally for the beta parameter combined adjusted betas from Value Line, Zacks and a regression analysis. The Delivery Group's average Value Line, Zacks and regression beta estimates were 0.67, 0.58, and 0.54, respectively. The Value Line regression employs 259 weekly observations of stock return data regressed against the New York Stock Exchange ("NYSE") Composite Index. Both the regression beta and Zacks betas employ sixty monthly observations; however, while Zacks betas regress stock returns against the S&P 500 Index, the regression beta regresses stock returns against the NYSE Index. Since the Zacks beta estimate and the regression

beta estimate are calculated using monthly data rather than weekly data (as Value Line uses), Mr. McNally averaged the Zacks and regression results to avoid over-weighting monthly return betas. He then averaged that result with the Value Line beta, which produced a beta for the Delivery Group of 0.62. Staff Ex. 5.0 at 24-29. For the risk-free rate parameter, Mr. McNally considered the 0.13% yield on four-week U.S. Treasury bills and the 2.77% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of November 9, 2012. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.3% and 4.9%. Thus, Mr. McNally concluded that the U.S. Treasury bond yield is currently the superior proxy for the long-term risk-free rate. Staff Ex. 5.0 at 19-24. Finally, for the expected rate of return on the market parameter, Mr. McNally conducted a DCF analysis on the firms composing the S&P 500 Index.

Staff's final number after inputting those three parameters into the CAPM, Mr. McNally calculated a cost of common equity estimate of 8.99% for the Delivery Group. The Utilities had a higher CAPM result with a cost of common equity estimate of 10.03%

We find that that both the Utilities' CAPM analyses and Staff's CAPM analyses have some merit and should be consider as an appropriate basis to determine ROE. As with the DCF analyses discussed above, The Commission does not endorse every input to or every aspect of the CAPM analyses performed by the Utilities or by Staff. Nevertheless, for purposes of this proceeding, the Commission finds that each provides useful input in estimating the market required return on common equity. In an effort to reach a reasonable result given all of the information in the record, the Commission notes that an average of these two models produce a value of 9.51% for the CAPM result.

In combining and averaging the DCF model of 9.15% and the CAPM analysis value of 9.51, the Commission estimates that for the Delivery group a reasonable estimate of the market required return on common equity is 9.33%

d. Risk Premium Analysis

The Commission concludes that it has not relied on a Risk Premium analysis and the Utilities have provided no appropriate information for the Commission to include the results from this model in its determination of the Utilities' ROEs.

e. Adjustments for Riders UEA and VBA

With respect to Rider UEA, the Commission finds that Staff's proposed adjustment is not warranted to be included in the ROE. Rider UEA has been in effect for the Utilities and hence there is no change in risk that has occurred since the last case that would warrant an adjustment here. Moreover, trackers such as Rider UEA have become quite common in the natural gas utility business. This adjustment had been made previously because most of the comparable Delivery Group companies had no bad debt tracker. However, 8 of the13 companies in the Delivery Group used had similar bad debt tracker. Therefore, there is no basis to make an adjustment to the

Utilities' cost of equity attributed to Rider UEA. Therefore, we reject Staff's proposed adjustment.

As to Rider VBA, the Commission finds that this issue was affirmed by the Appellate Court and the issue is therefore moot. Therefore, we conclude that no adjustment to the Utilities' ROE is required.

f. Conclusions

Based on the foregoing discussion, the calculation of ROE will be affected by the following conclusions: (1) the DCF analysis performed by the Utilities and for Staff for the Delivery Group will be included in this calculation; (2) the CAPM analysis of the Utilities and for Staff for the Delivery Group will be included in this calculation; (3) the Utilities Risk Premium analysis for the Delivery Group is rejected; (4) Staff's adjustment for Rider UEA is not accepted; and (5) the Utilities' adjustment for the legal challenge to Rider VBA is not accepted. Based on its review of the record and consistent with the conclusions above, the Commission finds that an average of the Staff's DCF and CAPM analysis along with the Utilities' DCF and the CAPM models forms an appropriate basis to determine ROE, which results in an ROE of 9.33% for each Utility.

F. Weighted Average Cost of Capital

North Shore

Based on the evidence in the record and the applicable legal principles, the Commission approves as just and reasonable an overall rate of return (weighted average cost of capital) for North Shore of 6.74%, calculated as follows:

North Shore Cost of Capital Summary			
Cost of Capital	**Percent of Total**	**Percent Cost**	**Weighted Cost**
Long Term Debt	42.33%	4.53%	1.92%
Common Equity	50.32%	9.33%	4.69%
Short Term Debt	7.35%	1.80%	0.13
Total Capital			6.74%

Peoples Gas

Based on the evidence in the record and the applicable legal principles, the Commission approves as just and reasonable an overall rate of return (weighted average cost of capital) for Peoples Gas of 6.69%, calculated as follows:

Peoples Gas Cost of Capital Summary			
Cost of Capital	**Percent of Total**	**Percent Cost**	**Weighted Cost**
Long Term Debt	43.61%	4.37%	1.91%
Common Equity	50.43%	9.33%	4.71%
Short Term Debt	5.96%	1.26%	0.08
Total Capital			6.70%

VII. WEATHER NORMALIZATION – AVERAGED PERIOD (Uncontested)

The Utilities proposed using the average of twelve years of weather data, ending in 2010. PGL Ex. 4.0 at 10; NS Ex. 4.0 at 10. No party disagreed.

The Commission finds that the proposed average is reasonable and appropriate.

VIII. COST OF SERVICE

A. Overview

Both North Shore and People Gas provided an embedded cost of service study ("ECOSS") with their filings. The ECOSS studies identify the revenues, costs, and profitability for each class of service and are the partial basis for the Utilities' proposed rate design. No other party presented an ECOSS study in this proceeding.

B. Embedded Cost of Service Study (Uncontested)

Utilities witness Ms. Hoffman Malueg testified that the ECOSS preparation involved three fundamental steps: (1) cost functionalization; (2) cost classification; and (3) cost allocation. NS Ex. 13.0 at 7-9; PGL Ex. 13.0 at 7-9. She explained in detail how she performed each of these three steps and the methodologies to allocate various categories of costs. NS Ex. 13.0 at 9-25; PGL Ex. 13.0 at 9-26. The Utilities' ECOSSs showed their overall rates of return under present and proposed rates. NS Ex. 13.0 at 34-36; PGL Ex. 13.0 at 35-37.

Neither Staff nor any intervenors contest the sufficiency of the Utilities' ECOSSs to allocate costs and design rates in this proceeding nor did they develop ECOSSs of their own. While no other party presented ECOSSs in this proceeding, the Commission notes that in their discussion of rate design some parties appear to take issue with some aspects of the underlying ECOSSs presented by the Utilities. The Commission understands the interrelationship between cost of service and rate design, however, the Commission also suggests that it is more helpful in reaching informed decisions on these complex issues if parties properly organize their discussion of the issues.

The Commission concludes that the Utilities' ECOSSs are complete, they systematically functionalize, classify and allocate costs, and they comport with the cost causation principles for preparing such studies that the Commission has approved in many other rate cases. Accordingly, the Commission finds that the Utilities' ECOSSs are sufficient and reasonable for allocating costs and designing rates in this proceeding. As noted above, the Commission understands the interrelationship between cost of service and rate design and while the Commission adopts the Utilities' ECOSSs for purposes of this proceeding, it will be mindful of ECOSS issues when considering rate design issues later in this Order.

IX. RATE DESIGN

A. Overview

The Utilities' proposed rate designs were intended to accomplish the following six major objectives: (1) recover the revenue requirement, (2) better align rates and revenues with underlying costs, (3) send proper price signals, (4) provide more equity between and within rate classes, (5) reflect gradualism considering test year revenue requirements, and (6) distinguish between low use and high use S.C. No. 1, Small Residential Service, customers as the Commission directed. NS Ex. 12.0 Rev. at 6; PGL Ex. 12.0 Rev. at 6.

B. General Rate Design

1. Allocation of Rate Increase

Utilities

The Utilities note that they used their ECOSSs to allocate revenue requirements and develop rates. They state that their ECOSSs and the descriptions of their rate designs, including the supporting exhibits, are detailed and specific enough that it would be straightforward to derive rates from the revenue requirements the Commission approves. NS Ex. 12.0 Rev. at 7-9; PGL Ex. 12.0 Rev. at 7-9. No other party prepared cost of service studies or a comprehensive rate design to meet the full revenue requirements the Commission approves. NS-PGL Ex. 32.0 at 33-34; NS-PGL Ex. 48.0 Rev. at 11-12. To the extent the AG's initial brief suggest a different approach for S.C. No. 1, the Utilities argue that the AG's proposal is unclear, unworkable, and incomplete at best. The AG's proposal only references exhibits from its witness' direct testimony, which is only for S.C. No. 1 heating rates. However, the Utilities will need to develop rates for all their service classifications, including the S.C. No. 1 non-heating and heating classes, following receipt of a final order. Also, the referenced exhibits are from AG witness Mr. Rubin's direct testimony, yet the AG's proposal appears to be an amalgam of his direct and rebuttal proposals. Moreover, the Utilities state that Mr. Rubin's proposals rely on the AG's proposed revenue requirement adjustments which the Utilities showed are flawed and problematic for many reasons. NS-PGL Ex. 48.0 Rev. at 13-18.

Staff

Staff states that it initially disagreed with the Companies' proposal for the setting of compliance rates, (Staff Ex. 8.0 at 23) but after further consideration agreed with the Companies' proposal. NS-PGL Cross-Ex. 10, NS-PGL 13.01. Staff explains that the compliance rates would be derived by first adjusting the ECOSS accounts and allocators based upon the Commission's findings. Then, the rate design approved by the Commission per class would be used along with the Companies' proposed rate design compliance methodology described in NS-PGL Ex. 32.0 at 33-34.

Commission Analysis and Conclusions

The Commission finds that the Utilities' ECOSSs are reasonable and should be used as a basis for allocating costs and designing rates in this proceeding.

2. Uniform Numbering of Service Classifications

Utilities

In response to a 2011 rate case directive (*Peoples Gas 2011* Order at 169), North Shore proposed changes to its service classifications to establish uniformity with Peoples Gas' service classification numbering to the extent possible. If approved, Utilities witness Ms. Grace stated that North Shore will make the required tariff revisions in its compliance filing. NS Ex. 12.0 Rev. at 25-26; PGL Ex. 12.0 Rev. at 26.

Staff

Staff witness Alicia Allen presented her review of North Shore's proposal for the uniform numbering of service classifications and recommended that the Commission adopt North Shore's proposal to renumber S.C. Nos. 3, 4, and 6 as S.C. Nos. 4, 7, and 5 respectively, to be uniform with the service classifications of Peoples Gas. NS Ex. 12.0 at 25-26; Staff Ex. 9.0.

Commission Analysis and Conclusions

The Commission finds that North Shore's proposal to conform its service classification numbering to Peoples Gas' format, to the extent applicable, is appropriate and meets the directive from the *Peoples Gas 2011* Order. The Commission directs North Shore, in its compliance filing, to make all tariff changes necessary to implement this proposal.

3. Bifurcation of S.C. No. 1 class

Utilities

Utilities witness Ms. Grace testified that the Utilities propose to split the S.C. No. 1 class into heating and non-heating classes in response to the Commission's directive

in the Utilities' 2011 rate case. *Peoples Gas 2011* Order at 188-189. The Utilities' proposal does not create separate service classifications, *i.e*., the customers would continue to receive service under S.C. No. 1 but at different rates. For clarity in the record, the Utilities refer to the heating and non-heating proposals as S.C. No. 1 HTG and S.C. No. 1 NH, respectively. NS Ex. 12.0 Rev. at 11-12; PGL Ex. 12.0 Rev. at 12.

The Utilities state that the Commission should adopt their proposal for several reasons. First, the record includes no alternative to their heating/non-heating split for the Commission to adopt, despite CUB-City's reference to the Commission adopting a "superior rate design" to address its low use/high use directive. Staff was the only party aside from the Utilities that provided comprehensive rate design testimony. CUB-City did not offer any rate design testimony and the AG offered rate design proposals for S.C. No. 1 based on the Utilities' proposed heating/non-heating split.

Second, the reasonableness of the Utilities' proposal is evident. It is uncontested that non-heating customers' usage is low. CUB-City state that 85% of Peoples Gas bills and 75% of North Shore bills for the proposed non-heating class are for 10 therms or less. CUB-City Init. Br. at 63. Further, 95% of North Shore non-heating customer bills are for 50 therms or less, and, annually, the average customer uses only 163 therms. NS-PGL Ex. 32.0 at 7-8. For Peoples Gas, 96% of non-heating customer bills are for 30 therms or less, and, annually, the average customer uses only 93 therms. *Id*. at 16. For the proposed heating class, 58% of North Shore and 52% of Peoples Gas bills are for more than 50 therms. *Id*. at 22, 27.

Third, in response to CUB-City's criticism that the Utilities did not study "individual customer usage, the Utilities point out that North Shore has more than 145,000 and Peoples Gas has more than 750,000 S.C. No. 1 customers. NS Ex. 13.5, PGL Ex. 13.5. Moreover, the purpose of an ECOSS is to identify the revenues, costs and profitability for each class of service, not for individual customers. NS Ex. 13.0 at 6; PGL Ex. 13.0 at 6; *also see* NS-PGL Ex. 33.0 at 6. The Utilities also note that this is clearly stated in the Commission's rules in which the required study is described as an ECOSS. 83 Ill. Adm. Code § 285.5110.

Fourth, the Commission's Order contemplated that a heating/non-heating split would be a possible outcome of its directive. *Peoples Gas 2011* Order at 188-189. The Utilities presented ECOSSs that distinguish between high and low use customers in the form of classifying customers as heating or non-heating. As Utilities witness Ms. Hoffman Malueg stated, "[i]t was my understanding that [Peoples Gas] and North Shore did propose a bifurcation of Service Class 1 in the past, and that the distinction kept in our [customer information system] of heating and non-heating followed the same general principles of low use versus high use." Tr. at 691.

Finally, the stated purpose of the Commission's directive in the Utilities' 2011 rate case is to better reflect customer class homogeneity. The Utilities' proposals achieve this purpose. The Utilities explain that some degree of non-homogeneity will necessarily exist in a rate class, but their proposal significantly increases S.C. No. 1 homogeneity. NS-PGL Ex. 33.0 at 6; Tr. at 684.

Staff

Staff notes that the Commission directed the Companies to present an ECOSS to distinguish between low use and high use S.C. No. 1 customers in Docket No. 11-0280/11-0281 (Cons.). The Commission stated:

> Therefore, in their next rate case, we direct the Companies to present an ECOSS to distinguish between low use and high use S.C. No. 1 customers. Such proposals may include, without limitation, a rate design including a demand charge or a bifurcation of the S.C. 1 class into heating and non-heating classes or some other rate structure that better reflects customer class homogeneity to bring each group's bills more into line with their respective costs of service.

Order, Docket Nos. 11-0280/11-0281 (Cons.), January 10, 2012 at 188-189.

Staff further notes that the Companies are proposing, in the current case, to bifurcate the S.C. 1 Small Residential Service class into heating and non-heating classes, as suggested by the Commission in Docket Nos. 11-0280/11-0281 (Cons.). PGL Ex. 12.0 Rev. at 12; NS Ex. 12.0 Rev. at 1-12.

Staff witness Johnson testified that he had no objection to the Companies' separation of the S.C. No. 1 Residential Service Class into heating and non-heating classes for rate design purposes. Staff Ex. 8.0 at 21. Mr. Johnson stated that the Companies' proposal to have heating and non-heating classes for rate purposes is a logical step considering the Companies' historical record keeping for heating and non-heating customers on their systems. For ratemaking purposes, it makes sense to separate the heating and non-heating customers because of the different demands they place on the system. Further, Mr. Johnson opined that the Commission was clear in its direction to the Companies in Docket Nos. 11-0280/11-0281 (Cons.) that they should present for the Commission's consideration a rate design that better reflects customer class homogeneity. The Companies' proposed rate design separates customers based upon historical data that reflects heating and non-heating cost of service demands. Separating the classes for cost of service purposes creates a greater homogeneity within each class in Mr. Johnson's view. *Id.*

Staff notes that the AG addressed the bifurcation of the S.C. No. 1 rate class into heating and non-heating classes, but did not provide a recommendation for or against it in its expert witnesses' testimony. However, since the AG has proposed both heating and non-heating rates it appears that it does not object to the Companies' bifurcation proposal. AG Ex. 3.0 R at 10, 15, 20, 24. Staff also notes that no other party provided written testimony addressing bifurcation of the S.C. No. 1 class.

CUB-City

CUB-City aver that this case marks the latest step in the Companies' quest for 100% cost recovery through fixed customer charges and further shifts their business risk to their captive residential customers. CUB-City note an unexpected gambit in that effort is the Companies' use of the Commission's directive to investigate cost distinctions between high-use and low-use customers, as cover for another increase in the percentage of costs recovered through charges customers cannot control.

CUB-City point out that Staff's rates expert noted the danger in allowing the Companies' to race toward ever larger customer charges without proper investigation or restraint. Mr. Johnson stated:

> I am concerned that the Company's proposed 93% fixed cost recovery for the S.C. No. 1 NH customers is excessive. The current S.C. 1 combined HTG and NH class customer charge recovers 68% of fixed costs. The Company's proposed S.C. 1 HTG fixed cost recovery is 75%. Since this is a new class the Commission should first observe what effects the S.C. 1 split has on the NH customers before moving to a greater fixed cost recovery that leaves little room for customers to adjust their bills.

Staff Ex. 8.0 at 29-30 (internal citations omitted). CUB-City contend Staff's caution about the unknown effects of the split is well-founded.

CUB-City observe that in the Companies' last rate case, the Commission "direct[ed] the Companies to present an ECOSS to distinguish between low use and high use S.C. No. 1 customers." Order, Docket No. 11-0280/0281, Jan 12, 2012 at 188-189. Though the Commission noted the possibility of a heating/non-heating split, it also pointed to "some other rate structure that better reflects customer class homogeneity to bring each group's bills more in line with their respective costs." *Id*.

CUB-City aver that the Commission could reasonably have expected the Companies to study more than one possible solution -- or at least investigate the one they preferred, to assure compliance with the Commission's directive. However, CUB-City state the Companies did neither. Instead, the Companies simply proposed the bifurcation of the residential class into separate heating/non-heating classes without substantive cost analysis.

CUB-City argue that the Companies were aware that usage is the driver of homogeneity (or its absence) in S.C. 1. They also knew that there are substantial usage variations within customer classes (Tr. at 684) even with the heating/non-heating split. Yet, CUB-City aver that the Companies did not undertake any investigation of individual customer usage. Tr. at 685-686. CUB-City explain that without conducting any study that would actually identify low-use and high-use customers, the Companies

simply proposed the bifurcation they preferred -- a rate-centered (not cost-centered) split that was easy and readily available.

CUB-City contend that the Companies' proposed heating/non-heating split was based as much on simple convenience as on any actual investigation or on empirical data that would identify high-use and low-use customers. Tr. at 690. This is evident from Companies witness Hoffman-Maleug's statement that "I would say it was analyzed as to how I could receive the data on our ECIS System" in response to the question of whether she made the decision to make the heating/non-heating distinction in the ECOSS. CUB-City point out that the Companies' cost of service expert was asked whether her testimony reports any investigation PGL performed that demonstrates that the heating/non-heating distinction used in her ECOSS would produce the "ECOSS that distinguishes between low-use and high-use Service Classification No. 1 customers." Order, Docket No. 11-0280/0281, Jan 12, 2012 at 188-189. Her response described the scant support the Companies offer: "Nothing beyond my exhibit and my cost of service model showing Service Class 1 designed (*sic*) between heating and non-heating." Tr. at 692-693.

CUB-City explain that as the Companies' cost of service expert, Ms. Hoffman-Maleug was the person responsible for complying with the Commission's Order. However, she used the heating/non-heating split as a surrogate for the ordered high use/low use bifurcation (Tr. at 690) -- with full knowledge that they are not equivalent and without any investigation of whether that split satisfied the Commission's directive. Tr. at 690, 692-693. CUB-City argue that although Ms. Hoffman-Maleug was supposedly responsible for providing an ECOSS that would address concerns about cost disparities for low use and high use customers, she did not make the decision on how to meet the Commission's directive. For these reasons, CUB-City do not believe the Companies presented evidence to show that a more diligent investigation either was not necessary or could not be performed.

CUB-City urge the Commission to consider seriously the alternative rate designs presented in this case. CUB-City state that one or more of them may address -- more effectively than the Companies' proposal -- the Commission's concerns about the subsidy from low use customers to high use customers, while providing cost recovery through just and reasonable rates. If the Commission does not identify and adopt a superior rate design from the record in this case, as identified herein, CUB-City do not oppose implementation of a heating/non-heating split -- on a provisional basis. CUB-City believe the proposed split drains less from low use customers through subsidies to high users customers than the existing rate design. However, continuation of that rate design split should be contingent on the presentation of evidence demonstrating that the heating/non-heating split mimics a low-use/high-use split at a reasonable degree of precision and eliminates improper subsidy flows to high use customers. CUB-City aver this evidence is necessary because no such evidence exist in this proceeding.

CUB-City find that the Companies' weak evidence supporting their compliance with the Commission's directive undercuts confidence in the Companies' proposed rate

design change. More important, as Staff recognized, it calls for extra care in imposing new, unknown burdens on customers. CUB-City state it is this backdrop against which the Commission must review the proposed rate designs presented in this record.

Finally, CUB-City aver that despite the failure of the Companies to investigate the usage characteristics across the residential class, regardless of service classification, one thing is clear from the Companies' ECOSS: the unique and very divergent usage characteristics of non-heating versus heating residential customers (which only generally corresponds to a low use/high use distinction) provides a justification for considering a bifurcation of the residential customer class into heating and non-heating customers. CUB-City state that the analysis cannot stop there however. CUB-City maintain that the rate design within each class also must consider the cost causation principles driving the Commission's directive in Docket Nos. 11-0280 and 11-0281 to investigate residential customer usage characteristics.

Commission Analysis and Conclusions

In the *Peoples Gas 2011 Order*, the Commission directed the Utilities "to present an ECOSS to distinguish between low use and high use S.C. No. 1 customers. Such proposals may include, without limitation, a rate design including a demand charge or a bifurcation of the S.C. 1 class into heating and non-heating classes or some other rate structure that better reflects customer class homogeneity to bring each group's bills more into line with their respective costs of service." In this proceeding, the Utilities have proposed to split the S.C.1 class into heating and non-heating classes. While both the AG and CUB-City express reservations about the implication of this proposal and the exact implementation, it appears neither has provided a reasonable or viable alternative.

Based upon its review of the record, the Commission finds that the Utilities' proposed split will more accurately reflect customer class homogeneity and the different demands that each customer class places on the system. The record in this proceeding seems to suggest that the proposed split properly distinguishes low and high use customers based on the Utilities' historical data which reflects heating and non-heating cost of service demands. Other rate designs may exist to accomplish this goal, however, no other party proposed an alternative method or presented ECOSSs that would provide an alternative proposal for distinguishing between low and high usage customers. Moreover, the record suggests that the method proposed by the Utilities addresses the Commission's concerns raised in the *Peoples Gas 2011 Order*. Accordingly, the Commission approves the Utilities' proposal to bifurcate S.C. No. 1 into heating and non-heating classes. The Commission also approves the Utilities' approach of including heating and non-heating rates in S.C. No. 1, rather than creating a new service classification.

4. Terms and Conditions of Service

Utilities

The Utilities propose adding language to address the proposed distinction between heating and non-heating S.C. No. 1 customers in the context of customers applying for service and remaining on the appropriate service classification. They also propose revising the bill format. NS Ex. 12.0 Rev. at 25; PGL Ex. 12.0 Rev. at 26.

Staff

Staff witness Allen presented her review of the Companies' proposed language specific to the Application for Service section which designates heating and non-heating classes as service classifications to restrict customers from switching service classifications more than once within a twelve-month period. PGL Ex. 12.1 at 9; NS Ex. 12.1 at 7. Ms. Allen recommends that the Commission adopt this language conditional on the Commission approving bifurcation of S.C. No. 1 into heating and non-heating customers. Staff Ex. 9.0.

Commission Analysis and Conclusions

The Commission finds that the Utilities' proposed changes to their Terms and Conditions are necessary and appropriate to implement the proposal to split S.C. No. 1 into heating and non-heating rates, which is discussed and approved above in Section IX.B.3.

C. Service Classification Rate Design

1. Uncontested Issues

a. Service Classification No. 2, General Service (Straight Fixed Variable Rate Design Addressed in IX.C.2)

Utilities witness Ms. Grace testified that with respect to S.C. No. 2, Peoples Gas is proposing to: maintain three meter classes; increase the monthly customer charges for each meter class to move the charges closer to cost, leaving 46% of fixed costs to be recovered through volumetric distribution charges; recover all customer costs and a portion of non-storage related demand costs through the customer charge; and maintain the three declining block distribution charge. She noted that Peoples Gas described in detail how it would develop rates based on the Commission-approved revenue requirement. PGL Ex. 12.0 Rev. at 19-21.

Ms. Grace further testified that North Shore made comparable proposals but its fixed cost recovery through volumetric distribution charges would be 33%. NS Ex. 12.0 Rev. at 19-21.

Ms. Grace stated that the Utilities are also proposing that Rider VBA remain in effect for S.C. No. 2 and that an alternative Straight Fixed Variable ("SFV") rate design

be implemented if, for specified reasons, Rider VBA is no longer in effect. These portions of the Utilities' proposal are addressed in Section IX.C.2 and IX.D. of this Order.

Staff witness Johnson testified that he did not object to the Utilities' proposal to increase the customer charges by meter class to the proposed fixed cost percentages. Mr. Johnson stated that they reflect greater fixed cost recovery and will recover all customer related costs. Even with the proposed increase in fixed cost recovery, the total fixed cost recovery for S.C. 2 will be approximately 64% for North Shore and 45% for Peoples Gas. Mr. Johnson opined that the Utilities' proposed increase in fixed cost recovery for S.C. 2 is consistent with the Commission's recent move towards increased fixed cost recovery. Additionally, customers will continue to have the opportunity to adjust their bills in order to reduce costs since 33% of total costs for North Shore and 46% of total costs for Peoples Gas will continue to be recovered through the distribution charge. Staff Ex. 8.0 at 33, 45.

Mr. Johnson also testified that he did not object to the Utilities' distribution charge proposals. He stated that, generally, customer-related costs not recovered in the customer charge are recovered in the first block of the distribution charge. The Utilities have stated that all customer-related costs and a portion of non-storage related demand costs will be recovered through the customer charge. Mr. Johnson recommended that the Utilities examine in their next rate case filing the feasibility of moving to two distribution blocks and also examine whether the current size therm blocks are still reasonable. Staff Ex. 8.0 at 33-34, 45-46.

The Utilities agreed with Staff's recommendation but noted that the recommendation would not be necessary under their SFV and modified SFV proposals. NS-PGL Ex. 32.0 at 30.

The Commission finds that each of Peoples Gas' and North Shore's S.C. No. 2 rate designs are appropriate and reasonable. The record supports this conclusion and the Commission believes that in this instance, moving greater fixed cost recovery to fixed charges is a sound rate design and consistent with long-standing Commission policy. As a general proposition, the Commission encourages the Utilities to move towards fixed cost recovery through fixed charges on a gradual basis.

The Commission also adopts Staff's proposal and orders the Utilities to examine the number and size of distribution charge rate blocks in their next rate case filings.

The Commission addresses the Utilities' alternative SFV proposals and Rider VBA elsewhere in this Order.

b. Large Volume Demand Service

Utilities witness Ms. Grace stated that Peoples Gas proposed, for its S.C. No. 4, Large Volume Demand Service, setting the monthly customer charge at cost. The demand charge will recover 55% of non-storage related demand costs, and the

distribution charge will recover remaining non-storage related demand costs. PGL Ex. 12.0 Rev. at 22.

Ms. Grace stated that North Shore proposed, for its S.C. No. 3, Large Volume Demand Service, setting the monthly customer charge at cost. The demand charge will recover 67% of non-storage related demand costs, and the distribution charge will recover remaining non-storage related demand costs. NS Ex. 12.0 Rev. at 21-22.

Staff witness Johnson stated that he did not object to the Companies' rate design proposal for the Large Volume Demand class. Mr. Johnson opined that the Companies are proposing to set the customer charge at cost, which is a minimal part of a customer's total bill since these customers must use an average of over 41,000 therms per month. Additionally, the Large Volume Demand class proposal will recover its full cost of service. Staff Ex. 8.0 at 34 and 46-47.

The Commission finds that the rate designs proposed by the Utilities for their large volume demand service classifications are appropriate and reasonable. It is proper to set these service classifications at cost, and the level of fixed demand cost recovery in demand charges is reasonable. The proposal is uncontested. The Commission approves the Utilities' proposed S.C. No. 3 (North Shore) and S.C. No. 4 (Peoples Gas) rate designs.

c. Service Classification No. 8, Compressed Natural Gas Service

Peoples Gas proposed to set S.C. No. 8, Compressed Natural Gas Service, at cost. PGL Ex. 12.0 Rev. at 22. North Shore does not have a comparable service classification. NS Ex. 12.0 Rev. at 25.

Staff did not object to Peoples Gas' rate design proposal for the S.C. No. 8 rate class. Staff opined that the charges will recover the full cost to serve the customers and the S.C. No. 8 class is available to any customer for gas to be used as compressed natural gas to fuel a vehicle. Staff believes it is important that the S.C. No. 8 class rates reflect the full class cost of service so customers can make informed decisions concerning their use of natural gas in vehicles and their possible purchases of natural gas vehicles. Staff Ex. 8.0 at 47.

The Commission finds that Peoples Gas' rate design for its compressed natural gas service classification is appropriate and reasonable. It is proper to set this service classification at cost. The proposal is uncontested. The Commission approves Peoples Gas' proposed S.C. No. 8 rate design.

d. Contract Service for Electric Generation

Contract Service for Electric Generation is a contract service whereby the prices to be paid and the terms and conditions of service are mutually agreed upon. North Shore is not proposing any changes to the Contract Service for Electric Generation

class. Peoples Gas is also not proposing any changes to the Contract Service for Electric Generation class. NS Ex. 12.0 Rev. at 22; PGL Ex. 12.0 at 22.

Staff did not object to the Companies' proposals. Staff Ex. 8.0 at 35, 48. The Commission approves the Utilities' proposals to make no changes to these contract service classes.

e. Contract Service to Prevent Bypass

North Shore stated that the sole negotiated contract for Contract Service to Prevent Bypass expires in 2012 and based upon discussions it has had with the customer, it anticipates that the customer is going to transfer to Large Volume Demand Service in the test year. North Shore has set the Contract Service to Prevent Bypass rates equal to the Large Volume Demand Service rates and has included the customer in the Large Volume Demand Service class for ECOSS purposes. NS Ex. 12.0 Rev. at 8-9. Peoples Gas is not proposing any changes to the Contract Service to Prevent Bypass. PGL Ex. 12.0 Rev. at 22.

Staff did not object to the Companies' Contract Service to Prevent Bypass proposals. Staff Ex. 8.0 at 35, 48. The Commission approves the Utilities' proposals to make no changes to these contract service classes.

f. Rider SSC, Storage Service Charge

The Utilities each proposed revising Rider Storage Service Charge ("Rider SSC") to change the Storage Banking Charge, which applies to transportation customers, and the Storage Service Charge, which applies to sales customers to meet their proposed storage-related revenue requirements. For North Shore, the production-related revenue requirement is also included in the calculation. The Commission-approved storage-related revenue requirement will determine the Rider SSC charges that the Utilities will include in their compliance filings. NS Ex. 12.0 Rev. at 23; PGL Ex. 12.0 Rev. at 23; NS-PGL Ex. 32.0 at 32.

Staff did not object to the Companies' proposal to make a change in the per therm charge for the storage service charge resulting from the new revenue requirements proposed in this proceeding. NS Ex. 12.0 Rev. at 23; PGL Ex. 12.0 Rev. at 23.

AG witness Rubin's direct testimony proposed that storage costs for the S.C. No. 1 non-heating class be recovered through the customer charge rather than through Rider SSC. AG Ex. 3.0 R at 11, 16. The Companies and Staff took issue with the AG's proposal and recommended that Rider SSC continue to be applicable to the S.C. No. 1 non-heating class. NS-PGL Ex. 32.0 at 9-12; Staff Ex. 17.0 at 2-23. The AG accepted the Companies' proposal to exclude storage related costs from the AG's initial proposal in order to minimize the contested issues in this case. AG Ex. 6.0 at 1-2.

The Commission directs the Utilities to file Rider SSC charges (Storage Banking Charge and Storage Service Charge) consistent with the revenue requirements it is approving in this Order.

2. Contested Issues – North Shore and Peoples Gas

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

Utilities

Utilities witness Ms. Grace stated that the Utilities each proposed, for S.C. No. 1 NH, recovery of 80% of non-storage related fixed costs through the customer charge, with recovery of all remaining costs through a flat distribution charge. NS-PGL Ex. 32.0 at 13-14, 19. S.C. No. 1 currently has a declining two block structure with a front block of 0-50 therms. Since about 95% of North Shore's S.C. No. 1 NH monthly bills are for 50 therms or less and about 96% of Peoples Gas' S.C. No. 1 NH monthly bills are for 30 therms or less, Ms. Grace reasoned that a flat rate structure is more appropriate than a blocked rate structure. NS Ex. 12.0 Rev. at 12; PGL Ex. 12.0 Rev. at 13; *also see* NS-PGL Ex. 32.0 at 7-8, 16.

Ms. Grace further testified that the Utilities would continue to recover storage-related fixed costs through Rider SSC. Rider SSC recovers the cost of storage on a uniform per-therm of capacity basis from transportation customers and on a uniform per-therm of usage basis from sales customers, with an annual reconciliation of revenues and costs. NS Ex. 12.0 Rev. at 8, 14; PGL Ex. 12.0 Rev. at 8, 14; NS-PGL Ex. 32.0 at 11, 18.

The Utilities explain that, increasing the level of costs recovered through the fixed customer charges would better align the charges with their underlying fixed costs and reduce the magnitude of Rider VBA adjustments. NS Ex. 12.0 Rev. at 15; PGL Ex. 12.0 Rev. at 15. They argue that it is also consistent with Commission policy. For example, in Docket No. 95-0032 the Commission urged Peoples Gas to increase the customer charge in future rate proceedings to move it closer to cost. In the Utilities' 2007 and 2009 rate cases, the Commission found it appropriate that rates reflect a greater recovery of fixed costs in customer charges. In a Union Electric case (Docket No. 03-0009), the Commission endorsed the utility's efforts to recover all of its fixed customer related costs of serving residential customers through the customer charge component of rates as well as a gradualism approach to doing so. The Commission allowed the Ameren gas utilities and Nicor to recover, for their residential and small commercial rate classes, 80% of their fixed costs through the customer charge. Finally, in the Utilities' 2011 rate cases, in connection with adopting Rider VBA on a permanent basis, the Commission again stated its support for increased recovery of fixed costs through fixed charges. *Peoples Gas 2011* Order at 188; NS Ex. 12.0 Rev. at 15-16; PGL Ex. 12.0 Rev. at 15-17.

The Utilities state that, as the Commission found in the 2011 rate cases (*Peoples Gas 2011* Order at 238) and it remains the case, all of the Utilities' S.C. No. 1 costs are fixed. Accordingly, the percentage of fixed costs recovered under Rider VBA should continue to be set at 100%. Under the Utilities' proposal, Rider VBA would remain in effect for S.C. No. 1, with a revised RCR and the Utilities propose alternative SFV rates if Rider VBA is no longer in effect for specified reasons. NS Ex. 12.0 Rev. at 14, 17; PGL Ex. 12.0 Rev. at 14, 17.

The Utilities state that AG witness Mr. Rubin's rate design proposal, given his willingness not to contest the applicability of Rider SSC to this rate, is not unreasonable. NS-PGL Ex. 32.0 at 9; NS-PGL Ex. 48.0 Rev. at 4. However, the Utilities accepted Staff's proposal in their rebuttal testimony. Staff's proposal, unlike the AG's, does not oppose the continued applicability of Rider VBA to this rate.

The Utilities argue that their proposed S.C. No. 1 non-heating rate design is consistent with the Commission's directive to present a bifurcated S.C. No. 1, shows reasonable and gradual movement towards greater fixed cost recovery through fixed charges, and includes a flat distribution charge, which is appropriate in light of the usage profile of customers who will receive service under this rate.

Staff

Staff urges the Commission to accept Staff's proposal to recover 80% of non-storage related fixed costs through the Companies' customer charge, which the Companies accepted in their rebuttal testimony. Staff contends that the Commission should also reject AG witness Rubin's proposal to implement a monthly flat rate with no distribution charge.

Staff explains that the Companies proposed in their direct testimony that fixed customer charges for North Shore recover 93% of fixed costs and 92% of fixed costs for Peoples Gas. NS Ex. 12.0 Rev. at 12; PGL Ex. 12.0 Rev. at 12. A flat distribution charge per therm for sales and transportation customers was also proposed. The current distribution charge consists of two blocks, 0-50 therms and over 50 therms. NS Ex. 12.4; PGL Ex. 12.4.

Staff witness Johnson was concerned that the Companies' proposed 93% fixed cost recovery for North Shore and 92% fixed cost recovery for Peoples Gas for the S.C. No. 1 NH customers would be excessive compared to the maximum fixed cost recovery amount of 80% approved by the Commission for Ameren and Nicor. Docket Nos. 07-0585 and 08-0363. Mr. Johnson noted that the current S.C. 1 combined HTG and NH class customer charge recovers 68% of fixed costs for North Shore and 57% for Peoples. Staff Ex. 8.0 at 30, 42. North Shore's proposed S.C. 1 HTG fixed cost recovery is 75% and 68% for Peoples Gas. NS Ex. 12.0 Rev. at 13; PGL Ex. 12.0 Rev. at 13. Mr. Johnson proposed recovery of 80% of non-storage related fixed costs through the customer charge and the remaining revenues collected through a declining two-block distribution rate structure in his direct testimony. Mr. Johnson's proposed 80% fixed cost recovery was based upon the percentage approved by the Commission for Ameren

and Nicor in Docket No. 07-0585 and Docket No. 08-0363, respectively. Staff Ex. 8.0 at 31, 43.

Staff notes that the Commission has not approved fixed cost recovery above 80% at this juncture. Staff further points out that even under Staff's proposed 80% fixed cost recovery for the S.C. No. 1 non-heating class there is a dramatic decrease in the customer charge compared to the current combined S.C. No. 1 class. The decrease in the customer charge for non-heating customers, even at 80% fixed cost recovery, is a clear indication of the cost differences between heating and non-heating customers that was not apparent when the heating and non-heating customers were combined for ECOSS purposes. Using the Companies' proposed direct testimony revenue requirement, the customer charge for the non-heating group would decrease from $22.00 per month to $14.48 for North Shore and from $22.25 per month to $13.63 for Peoples Gas. NS-PGL Exs. 32.5, 32.6.

Staff observes that in rebuttal testimony, the Companies accepted Staff's proposal to recover 80% of non-storage related fixed costs through the customer charge. However, the Companies disagreed with Staff's proposed two-declining block distribution charge and instead continued to recommend a flat distribution charge. NS-PGL Ex. 32.0 at 7,16.

Staff witness Johnson accepted the Companies' proposed flat distribution charge in rebuttal testimony. Mr. Johnson initially had concerns with bill impacts for customers using more than 250 therms per month but after further review noted that 95% of total bills for North Shore are for 50 therms or less and 96% of the total bills for Peoples Gas are 30 therms or less. For North Shore, 250 therms and above only represents 0.46% of total bills and for Peoples Gas it represents 0.13%. While some bills will fall into the higher usage categories, they are a small percentage of total bills and customers have the option of cutting back on usage to lower bills if they so desire. Additionally, Staff explains that moving to a flat block distribution charge will lower the amount per therm charged to low use customers (those customers using 50 therms or less). Staff Ex. 17.0 at 5-6.

Staff witness Johnson disagreed with AG witness Rubin's S.C. No. 1 NH rate design proposal. First, Mr. Johnson stated that even though 85% of bills for PGL and 71% of bills for NS are for ten therms or less that still leaves 15% for PGL (199,802 bills) and 29% NS (6,585 bills) that are above 10 therms. In fact, there are 2,633 bills for PGL usage above 200 therms, ranging from 200 therms to over 1,000 therms. Likewise, there are 142 bills for NS usage above 200 therms, ranging from 200 therms to approximately 900 therms. Staff Ex. 17.0 at 21. So even though there are a high percentage of bills that are for 10 therms or less, there are still customers that use greater therms and place different demands on the system. Second, Mr. Johnson testified that even though the difference between typical winter and summer usage for the residential non-heating class, as identified on AG Exhibit 3.01 and 3.04, is small, there is a distinct pattern of increased usage in the winter months. Mr. Johnson reasoned that this indicates that the non-heating residential class is placing greater

demands on the system in the winter compared to the summer months. So even though a large percentage of non-heating customers may be using 10 therms or less, there are some customers in the non-heating class that are using more therms and should be charged for the different demands they place on the system. Staff Ex. 17.0 at 21. Third, Mr. Johnson pointed out that the Commission has previously stated that leaving a portion of fixed costs to be recovered through the volumetric rate (20%) would encourage companies to see ways to improve efficiency and otherwise cut costs. Order, Docket No. 07-0585 et al. (Cons.), September 24, 2008 at 237; Order, Docket No. 08-0363, March 25, 2009 at 90-91. The Commission has also noted that if all of their fixed costs were recovered through the monthly charge, companies may arguably over-recover their fixed costs through the monthly charge. *Id*.

With respect to AG witness Rubin's proposal for storage costs to be recovered through the customer charge rather than through Rider SSC, Mr. Johnson explained that because storage costs are demand related, they should be recovered on a per therm basis. Under Mr. Rubin's flat rate customer charge proposal, all non-heating customers would pay the same monthly flat rate, except for the cost of gas, regardless of the amount of therms they use and the demands they place on the system. Mr. Johnson testified that it is not reasonable that customers with different demands pay the same charge for storage, even if there are not large differences in their demands. Therefore, Staff recommends that Rider SSC remain applicable to SC No. 1 NH customers. Staff Ex. 17.0 at 22-23.

AG

The AG contends that all of the parties' proposals, and indeed the Companies' ECOSS, point to the fact that PGL and NS residential non-heating customers are currently paying rates that are significantly higher than the costs they impose on the Companies' delivery systems. According to the AG, the uncontested evidence of record shows that the rates PGL currently charges to residential non-heating customers exceed the cost to serve those customers by more than $10 million per year. This is equivalent to non-heating customers paying PGL an overall return of 74.16% (line 37), or roughly 10 times the required level of return (7.44%) that PGL claims in this case. AG Ex. 3.0 at 6-7. With regard to North Shore, the uncontested evidence of record shows the rates it currently charges to residential non-heating customers exceed the cost to serve those customers by more than 35%. This is equivalent to non-heating customers paying NS an overall return of 70.16% (line 38), or roughly nine times the required level of return (7.65%) that NS claims in this case. AG Ex. 3.0 at 12-13.

The AG maintains that these facts alone prove that the Companies' assertion that all costs are fixed is completely erroneous and contrary to its own cost studies. The Companies' witness, Staff witness Johnson and AG witness Scott Rubin all propose significant reductions in the customer charge for non-heating residential customers, consistent with the results of the ECOSS, which the AG argues revealed the significant cross subsidies between non-heating and heating customers, and within the heating class as a whole. The AG notes that all parties agree that the residential non-heating

rates need to be reduced to ensure equity and prevent cross-subsidization. The differences in the rate design proposals among the Companies, Staff and AG witness Scott Rubin are fairly minor.

It is the AG's view that the record evidence shows that the non-heating class is extremely homogenous. PGL's billing analysis shows that 85% of bills issued to non-heating customers are for 10 therms per month or less. PGL Sched. E-8 at 3. In contrast, one-third of bills issued to heating customers are for 100 therms or more in a month, with about one out of every seven bills showing usage of more than 200 therms in a month. PGL Sched. E-8 at 2; AG Ex. 3.0 at 8. Likewise, for North Shore, the differences are similar, but not identical, to those described in PGL's service area. NS's billing analysis shows that 75% of bills issued to non-heating customers are for 10 therms per month or less. NS Sched. E-8 at 3. In contrast, 39% of bills issued to heating customers are for 100 therms or more in a month; with about one out of every seven bills showing usage of more than 200 therms in a month. NS Sched. E-8 at 2; AG Ex. 3.0 at 13.

The AG argues that further evidence of the homogeneity of the non-heating class can be found in AG Ex. 3.02, which revealed that the difference between typical winter and summer usage for the PGL non-heating class is quite small – differing by fewer than 10 therms per month. AG Ex. 3.0 at 12. The AG also argues that likewise as explained above and shown on AG Ex. 3.05, the difference between typical winter and summer usage for the NS non-heating class is quite small – differing by fewer than 15 therms per month. AG Ex. 3.0 at 17.

AG witness Rubin proposed a flat monthly charge for all residential non-heating customers that recovers essentially all base rate costs (that is, all costs except municipal taxes and the commodity cost of gas). PGL's cost-of-service study calculates this cost to be $17.19 per month. PGL Ex. 13.7 at 3.

Mr. Rubin recommended for PGL a flat non-heating charge of $15.35 per month. He explained that this is a reduction of $6.90 per month from the existing customer charge, and the complete elimination of the per-therm charge (except for Rider SSC). In addition, Mr. Rubin recommended for NS a flat non-heating charge of $16.05 per month. He explained that this is a reduction of $5.95 per month from the existing customer charge, and the complete elimination of the per-therm charge (except for Rider SSC).

The AG asserts that a flat rate (or SFV rate) would be appropriate only in the relatively rare instance when a customer class is homogeneous. AG witness Rubin testified that the residential non-heating class meets that criterion. Unlike the residential heating class, the PGL non-heating class is quite homogeneous, *with 85% of bills containing usage of 10 therms or less*. PGL Sched. E-8 at 3; AG Ex. 3.0 at 17. The NS non-heating class is likewise quite homogeneous, with 75% of bills containing usage of 10 therms or less. NS Sched. E-8 at 3. Further, the AG notes that as discussed above,

the difference between typical winter and summer usage for the Companies' non-heating class is quite small.

The AG argues that the Commission should adopt its proposals because they more accurately reflect the homogeneity of the non-heating residential class, provide 100% cost recovery for the PGL and NS non-heating customer class and simplify the non-heating rate structure. The AG also clarifies that Mr. Rubin agreed in his rebuttal testimony to the Companies' proposal to recover storage related costs through Rider SSC, rather than through the customer charge. Staff's assertion that his position was something different overlooks this compromise on this point.

CUB-City

CUB-City aver that the record evidence in this proceeding demonstrates the unfairness and inequities of the Companies' existing residential rate structure. CUB-City maintain that the very high customer charges that result from the partial SFV rates approved by the Commission in the Companies' last rate proceeding have proven to be grossly unfair to low-use customers and are wholly unrelated to the actual costs of servicing these customers. AG Ex. 3.0R at 7. CUB-City find the fundamental flaw in SFV rates is that they treat demand-related costs as "fixed" even though they are incurred based on the amount of gas customers use. *Id*. at 7. CUB-City contend this point is validated by the results of the Companies' respective ECOSS. The Companies' ECOSS found that the existing rates paid by non-heating customers recover greatly in excess of the cost of serving that customer class. This consequence of the steep increase in fixed charges on the residential class was identified and predicted by AG witness Rubin in the Companies' last case. See, e.g., January 10, 2012 Order, Docket No. 11-0282 at 143. CUB-City aver that good rate design policy dictates that the non-heating customers' uniquely low peak demand should correspondingly result in lower demand-related costs than the generally higher average peak demand represented by the heating class.

CUB-City explain that for Peoples Gas, the results of the ECOSS, which includes only costs related to delivery services, show that residential non-heating customers provide base-rate revenues of $31,960,081, but the total cost to serve these customers is $21,735,396. AG Ex. 3.0R at 6-7. Thus, PGL's residential non-heating customers pay more than $10 million more per year than the cost to serve them, for an overall return of 74.16%. *Id*. at 7. Similar results are demonstrated for North Shore customers: the ECOSS shows that under present rates, residential non-heating customers provide base-rate revenues of $528,013, but the total cost to serve those customers is $390,723. *Id*. at 13. NS's residential non-heating customers therefore pay 35% in excess of their cost of service, or an overall return of 70.16%. *Id*.

CUB-City further explain that non-heating residential customers are paying far in excess of the cost to serve them because of the very high customer charges that were approved in the Companies' last rate case. These gross inequities between cost of service and class revenues result from spreading demand-related costs among all

customers, on a per account basis, while ignoring the actual demand those customers impose on the system. AG Ex. 7. Non-heating customers, who have very low peak-demand requirements compared to heating customers, must pay the same toward demand-related costs as heating customers who may use 10 to 20 times more gas and who drive peak demand on the system. *Id*. A North Shore residential heating customer has a winter peak month that is 10.5 times the lowest summer month, but for non-heating customers, it is only 3.2 times. AG Ex. 3.04. Thus, CUB-City state, not only do heating customers use much more gas than non-heating customers, but they have dramatically steeper peak demands, during peak demand periods. CUB-City argue that recovering demand-related costs on a per customer, rather than a per therm basis, as the rates are currently aligned, causes non-heating customers to subsidize the rates of heating customers. *Id*. Because demand-related costs are aligned with gas consumption, CUB-City aver they should be recovered on a volumetric basis rather than in the fixed monthly customer charge. CUB-City explain that the bifurcation of the heating and non-heating residential classes partially mitigates the subsidies stemming from the vastly different usage characteristics of the residential class.

CUB-City aver that the Companies partially address the existing incontrovertible inequity in the non-heating customer class by proposing rate reductions to this class. NS-PGL Ex. 12.0 at 8. In addition, CUB-City note that given Mr. Rubin's modification to his proposed non-heating rate design, it appears from the record that the Companies and the AG may agree on one potential acceptable rate design for the non-heating residential class.

Commission Analysis and Conclusions

The Utilities propose that the Commission increase the amount of non-storage related fixed costs recovered through fixed charges in the S.C. No. 1 NH customer class. Specifically, the Utilities propose, as revised in response to Staff's testimony, for S.C. No. 1 NH to recover 80% of non-storage related fixed costs through the customer charge, with recovery of all remaining non-storage related costs through a single flat distribution or usage charge. The Utilities' proposed rate design also includes a proposal to continue to recover storage related fixed costs through Rider SSC. The current S.C. 1 combined HTG and NH class customer charge recovers 68% of fixed costs for North Shore and 57% for Peoples Gas.

The Commission finds that the Utilities' rate design, as revised, is appropriate and reasonable. While the Commission supports the recovery of more fixed costs through fixed charges, the Commission continues to believe this movement should be done gradually and conservatively mindful of ensuring that the Utilities' do not over-recover their fixed costs through the monthly fixed charge. Additionally, the record supports a finding that the remaining fixed non-storage costs should be recovered through a single flat distribution charge. The Commission believes this rate design will ensure that the Utilities do not over-recover their costs through the monthly fixed charge and will reflect the underlying costs of providing service to customers with different usage patterns. Finally, the Commission finds that it is appropriate for storage related

costs to be recovered through Rider SSC for this customer group. It appears this final issue is no longer contested.

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

The Utilities each propose, for S.C. No. 1 HTG, recovery of 80% of non-storage related fixed costs through the customer charge, with recovery of all remaining non-storage costs through a flat distribution charge. The Utilities maintain that they showed that moving to a flat distribution charge from the current declining two-block rate produces more favorable bill impacts than those derived from the Staff and AG proposals that retain a blocked distribution charge. NS-PGL Ex. 32.0 at 23, 27.

The Utilities propose to continue to recover storage-related fixed costs through Rider SSC. Rider SSC recovers the cost of storage on a uniform per-therm of capacity basis from transportation customers and on a uniform per-therm of usage basis from sales customers, with an annual reconciliation of revenues and costs. NS Ex. 12.0 Rev. at 8, 13-14; PGL Ex. 12.0 Rev. at 8, 12, 14.

The Utilities, citing the Commission's findings in the 2011 rate cases (*Peoples Gas 2011* Order at 238), state that it remains the case that all of the Utilities' S.C. No. 1 costs are fixed. Accordingly, the percentage of fixed costs recovered under Rider VBA should continue to be set at 100%. The Utilities believe that increasing the level of costs recovered through the fixed customer charges would better align the charges with their underlying fixed costs and reduce the magnitude of Rider VBA adjustments. NS Ex. 12.0 Rev. at 15; PGL Ex. 12.0 Rev. at 15. They argue that it is also consistent with Commission policy.

The Utilities state that their fundamental disagreement with Staff's proposal is the insignificant movement towards greater fixed cost recovery through fixed charges. The Utilities maintain that Staff's proposal is contrary to longstanding Commission policy. In addition, the Utilities state that Staff's S.C. No. 1 proposals produce the incongruous recommendation that, absent Rider VBA, the Utilities' S.C. No. 1 HTG rate would be the only small residential rate class with less than 80% fixed cost recovery among the state's largest utilities. NS-PGL Ex. 32.0 at 35.

The Utilities argue that Staff's assertion "price signals" is a good reason for leaving non-storage related demand costs in the distribution charge as it will "encourag[e] conservation" is contrary to the Commission's observation in a Nicor Gas rate case that "[t]he portion of fixed costs that are currently recovered through a volumetric charge are in fact fixed costs, and thus cannot be conserved. Moving a greater percentage of fixed cost recovery to fixed charges rather than volumetric charges provides a more stable revenue stream <u>and sends a better price signal to the consumer</u>." (emphasis added) *In re Northern Illinois Gas Company d/b/a Nicor Gas Company*, ICC Docket No. 08-0363 at 91 (Order Mar. 25, 2009).

To illustrate the flaw in Staff's proposal, the Utilities state that one example of a type of costs classified as demand is transmission and distribution mains designed to meet customer maximum peak day demand. NS Ex. 13.0 at 8; PGL Ex. 13.0 at 8. Under Staff's proposal, the Utilities argue a customer who uses less gas will not pay his share of the costs associated with the main(s) that serve the customer because Staff would place recovery of demand costs in a volumetric charge. According to the Utilities, under Staff's proposal, if a customer's peak day usage increases but usage on non-peak days declines in a greater quantity, the customer pays less than the allocated cost of the main from which it takes service even though its demand on that main increased.

The Utilities state that the AG's and CUB-City's disagreement with the Utilities' S.C. No. 1 HTG proposal is largely about the nature of costs classified as "demand." The Utilities explain that demand-related costs are fixed costs. As the Commission concluded in the Utilities' 2009 rate cases, "[w]e find compelling Ms. Grace's explanation that demand costs (also known as capacity costs) are fixed costs and not volumetrically based." *Peoples Gas 2009* Order at 225. The Utilities state that in ordering the Utilities to adopt Rider VBA on a permanent basis, the Commission ordered the Utilities to set the percentage of fixed costs at 100% (*Peoples Gas 2011* Order at 238), *i.e*., finding that all the Utilities' costs, which would include demand-related costs, are fixed.

The Utilities explain that, although demand-related costs may be spread among rate classes using certain usage based allocation methodologies, demand-related costs do not vary with customers' usage and cost-based ratemaking does not require that they be recovered through distribution charges. The Utilities cite the Gas Distribution Rate Design Manual Prepared by the National Association of Regulatory Utility Commissioners ("NARUC") in support:

> The most controversial issue is deciding where capacity [demand] costs belong in the rate. Because they are fixed costs, it is sometimes argued that they should be part of the customer charge. On the other hand, it can be argued that … those common fixed costs should be recovered evenly from all units of commodity sold. It is even occasionally proposed that these costs be spread between customer and commodity [distribution] charges.

The Utilities maintain that this passage confirms that demand-related costs are fixed, but acknowledges that a few acceptable methodologies exist for recovering such costs. The Utilities believe they showed that, consistent with accepted methodologies and recent Commission policy, such fixed costs should be recovered through a fixed charge such as the customer charge. Nonetheless, in the interest of rate design continuity and gradualism, they proposed, if Rider VBA remains in effect, to spread such costs between the customer and distribution charges for S.C. No. 1 NH and HTG customers. NS-PGL Ex. 48.0 Rev. at 8; *also see* NS-PGL Ex. 33.0 at 8.

The Utilities explain that it is clear from the definition of costs classified to the demand classification that the key is the customer's usage on the peak or the coldest winter day, *i.e*., the customer's maximum peak day demand. NS Ex. 13.0 at 8; PGL Ex. 13.0 at 8; Tr. at 674. It is not mere day-to-day variations in usage that drive demand costs. By contrast, the commodity-related costs are those that vary with throughput sold or transported to customers. NS Ex. 13.0 at 8; PGL Ex. 13.0, 8; Tr. at 674.

The Utilities contend that the Commission should reject AG witness Mr. Rubin's proposal. It provides an even lesser amount of fixed cost recovery through fixed charges than Staff's and is inconsistent with sound rate design proposals and Commission precedent. NS-PGL Ex. 32.0 at 21-22, 26-27. The Utilities argue that the Utilities' proposals will have a more favorable bill impact on customers at varying usage levels than the AG's and Staff's proposals. *Id*. at 23-25, 27-29; NS-PGL Exs. 32.7, 32.8, 32.9, 32.10.

The Utilities challenge the AG's and CUB-City's contention, citing diverse home sizes, that the S.C. No. 1 heating class is not homogenous. The Utilities state that the intervenors implicitly assume that larger homes, in all cases, use more gas than smaller dwellings. However, many factors affect customers' gas usage such as the energy efficiencies of the dwelling and its appliances, the number of people in the household, the ages of household members, individual comfort preferences and employment status, among others. NS-PGL Ex. 32.0 at 23; NS-PGL Ex. 48.0 Rev. at 9.

Finally, the Utilities explain that, in support of its rate design proposal, the AG cites various provisions in Section 1-102 of the Act and describes them as "statutory requirements." AG Init. Br. at 113. However, the Utilities state that Section 1-102 of the Act, Findings and Intent, does not set forth "statutory requirements." "Section 1–102 of the Public Utilities Act is nothing more than prefatory. As such, it is of no substantive or positive legal force." *Monarch Gas Co. v. Illinois Commerce Comm'n.*, 261 Ill. App 3d 94, 99 (5th Dist. 1994) appeal denied 157 Ill. 2d 505 (1994).

Staff

Staff urges the Commission to accept its proposal to increase fixed cost recovery for North Shore to 68%, from its current 67%, and increase fixed cost recovery for Peoples Gas to 61%, from its current 54%, instead of the 80% the Companies propose for both North Shore and Peoples Gas.

Staff witness Johnson had no objection to the Companies' proposal to move to a flat distribution charge for the S.C. No. 1 HTG class. However, Mr. Johnson disagreed with the Companies' proposal to shift the non-storage related demand costs from the distribution charge to the customer charge for S.C. No. 1 HTG class. Staff Ex. 8.0 at 25, 37. Mr. Johnson proposed recovering the non-storage related demand costs through the distribution charge. His proposal increases the fixed cost recovery for North Shore to 68%, from its current 67% fixed cost recovery, and increases the fixed cost recovery for Peoples Gas to 61%, from its current 54% fixed cost recovery. Mr. Johnson stated that Peoples Gas customers under present rates currently pay 25.963

cents per therm for the first 50 therms and 11.806 cents per therm for anything over 50 therms. Peoples Gas' shifting of the distribution charge costs to the customer charge shifts the price signal customers receive from the distribution charge. Approximately 48% of total bills are attributed to 50 therms or less which, currently, is charged at the 25.963 cents per therm. Mr. Johnson explained that decreasing the current distribution charge from 25.963 cents per therm to 10.054 cents per therm, as Peoples Gas' proposed in rebuttal testimony in order to recover 80% of fixed costs in the distribution charge, will not encourage customers to use less gas. NS-PGL Ex. 32.3. Leaving the non-storage related demand costs in the distribution charge will ease the move to a flat rate while still encouraging conservation.

Staff asserts that the Companies' proposal to bifurcate the S.C. No. 1 class will affect the two customer groups differently. For example, the bifurcation produces the counter-intuitive result that the customer charge for the non-heating class decreases even though the percentage of fixed costs recovered through that customer charge increases under both Staff's and the Companies' proposals. This occurs because the bifurcation produces a reduction in the customer charge for the non-heating class that more than offsets the increase that would result from either Staff's or the Companies' fixed cost recovery proposals. This is not the case for the heating class according to Staff. For this reason, Staff states that the Commission should observe what effects the S.C. 1 split has on all of its residential customers before moving forward on significantly greater fixed cost recovery through the customer charge. Staff Ex. 8.0 at 25-26, 41.

AG

The AG argues that the requirement in Section 9-201 of the Act that requires the Commission in a contested case to determine whether the rate increases proposed by a utility are "just and reasonable" extends to the design of utility rates. To make this ultimate determination, the Commission must resolve disputed factual issues, but it must also consider certain equitable and policy considerations.

According to the AG, these statutory requirements, coupled with the results of the Companies' ECOSS, clearly establish that demand for natural gas has a substantial effect on cost incurrence, and point to the need for the Commission to revisit its acceptance of the utilities' claim that all of its costs are "fixed" and that the Companies' customer charges – particularly for heating customers – must continually be increased relative to the variable usage charges. PGL's residential heating class proposals neither recognize nor appropriately recover the substantial demand-related costs that PGL incurs to serve heating customers. The AG argues that except in the rare case when a customer class is relatively homogeneous, it is improper to recover demand-related costs on a per-customer basis by increasing the flat customer charge. AG Ex. 3.0 at 18.

The AG contends that the same problem exist within the heating class. Data from various sources, including housing surveys, shows that there is great diversity within the housing stock in the Utilities' service territories. The size of the homes and apartments

of the customers varies greatly which indicates the diversity of the residential heating class. AG Ex. 3.0 at 18-19.

The AG argues that the Companies' proposed residential heating rates fail to recognize or appropriately recover demand-related costs. As noted by Mr. Rubin, PGL has proposed a per-therm distribution charge of 13.343¢ per therm for all consumption by residential heating customers. PGL's ECOSS, however, shows that PGL's demand-related cost is approximately 29% higher than its proposed rate per therm. In addition, NS has proposed a per-therm distribution charge of 7.742¢ per therm for all consumption by residential heating customers. NS's ECOSS, however, shows that NS's demand-related cost is approximately 35% higher than its proposed rate per therm. AG Ex. 3.0 at 23.

In light of these facts, Mr. Rubin recommended customer charge levels that recover less demand-related costs than the 80% level proposed by the Companies. Under Mr. Rubin's proposal, PGL would recover 55% of residential heating customer costs through the customer charge and 60% of NS heating costs. *See* AG 6.03 (PGL) and 6.04 (NS) at 3.

He also recommended that the Companies retain two consumption blocks in its residential heating rate. The first block would recover demand-related costs plus a portion of the customer-related costs that were allocated to the distribution system, primarily through an allocation of distribution mains. According to Mr. Rubin, treating some distribution costs as being customer-related is controversial and depends on statistical analyses that can be of questionable validity. But rather than engage in a debate about those analytical procedures in this case, Mr. Rubin testified that it is reasonable to recover some of that allegedly customer-related distribution cost through the first 50 therms per month that are sold. Recovering these costs in the first consumption block will provide PGL with significant stability in the recovery of those revenues (because heating customers by definition will use the service) and will not distort the demand-related price signal that is sent to customers in the second, more weather-sensitive consumption block. AG Ex. 3.0 at 20.

Mr. Rubin testified that it could be argued that all of the allegedly customer-related portion of distribution costs should be recovered through the first block charge. Doing so, however, would decrease the customer charge by about 50% and approximately double the first block charge. In his opinion, such a result is not consistent with sound rate design principles, including the principles of gradualism and rate continuity, because PGL already has been permitted to greatly increase its customer charge. He recommended, therefore, that 75% of customer-related distribution costs should be recovered through the customer charge, with the remaining 25% of those costs recovered through the first consumption block charge. *Id.* at 20-21.

Mr. Rubin calculated residential rates for both Peoples Gas and North Shore that would implement the AG witness's rebuttal revenue requirement recommendations. AG Ex. 6.03 is a three-page analysis that shows Mr. Rubin's calculation of S.C. 1 rates for

PGL. Page 1 of the exhibit shows a comparison of PGL's present rates, PGL's proposed rates (from its rebuttal filing), and his proposed rates. For heating customers, the AG's revenue requirement would be collected if PGL charged a customer charge of $23.99 per month (an increase of $1.74 over the current charge), a first-block charge of 29.148¢ per therm (a decrease of less than one cent per therm), and a second-block charge of 16.793¢ per therm (an increase of less than one cent per therm). The calculation of these rates is shown on pages 2-3 of that exhibit.

AG Ex. 6.04 contains a similar analysis for North Shore. For heating customers, the AG's revenue requirement would be collected if NS charged a customer charge of $20.51 per month (a reduction of $1.49 per month compared to the current charge), a first-block charge of 17.939¢ per therm (an increase of three-tenths of a cent), and a second-block charge of 9.754¢ per therm (an increase of about four cents per therm). The calculations of these rates are detailed on pages 2-3 of AG Ex. 6.04.

The AG urges the Commission to adopt its proposal instead of the Companies'. Under Mr. Rubin's proposal, PGL would still recover 55% of residential heating customer costs through the customer charge and 60% of NS heating costs, without punishing the Companies' lower users of heating delivery service. The AG argues these proposed rates are more equitable than the Companies, and acknowledge the Commission's stated interest in ameliorating subsidies within the heating class. *See Peoples Gas 2011* Order at 178.

The AG contends that even if one assumed that the Commission had previously concluded unequivocally that all of the Companies' costs are fixed in a previous order, the concept of public utility regulation requires that the Commission have power to deal freely with each situation that comes before it, regardless of how it may have dealt with a similar or even the same situation in a previous proceeding. *Mississippi Fuel Corp. v. Illinois Commerce Comm'n,* 1 Ill.2d 509, 513 (1953). A record containing new evidence or argument that implicates past decisions compels reconsideration on the new record and may require a different result. *See Commonwealth Edison Co. v. Illinois Commerce Comm'n*, 405 Ill.App.3d 389,408 (2nd Dist. 2010), citing 220 ILCS 5/10-103 ("any finding, decision or order made by the Commission shall be based exclusively on the record for decision in the case").

The AG argues that the record in this case supports Commission rejection of the assumption that all of the Companies' costs are fixed. The AG asserts that the Companies' costs vary with the volume of natural gas delivered to customers, contrary to the Utilities' assertion otherwise. In addition, while the Companies note that the notion of increasing the customer charge to recover "fixed" costs dates back to 1995, the AG maintains that the Commission did not in fact conclude in that Order that all of the Companies' costs were fixed.

The AG further notes that the Commission's 2007 PGL/NS rate case order set the customer charge at 50% of the Companies' costs. That position is more in line with Mr. Rubin's proposal to recover 55% and 60%, respectively, of PGL's and NS's

residential heating customer costs through the customer charge. The AG contends that in no way does the 2007 Order support an 80% modified straight fixed variable customer charge rate, as proposed by the Companies. Moreover, although the 2009 Rate Order cited by the Companies increased the amount of costs recovered through the customer charge, it did not address the issue of cross-subsidization between and among low-and high-usage customers that is now being examined by the Commission, as required in the *Peoples Gas 2011* Order. The AG states that the *Peoples Gas 2011* Order, relied on the Ameren and Nicor decisions which are factually distinguishable and do not support the radical increase in the customer charge being proposed by the Companies in this docket.

The AG states that it is true that the Commission allowed the Ameren gas utilities and Nicor Gas to recover, for their residential and small commercial rate classes, 80% of their costs through the customer charge. However, the AG argues a review of those orders shows that those conclusions were based on facts that cannot be applied in this docket. Unlike this proceeding, there was no cost of study filed in the Ameren case detailing residential costs of service. The ALJ randomly selected the 80% recovery amount as an alternative to Ameren's request for a full decoupling rider, rather than a specific proposal set at that 80% amount. Moreover, in approving that amount of recovery of costs through the customer charge, the Commission noted first that Ameren was experiencing declining sales in the residential class, and that less recovery of costs through volumetric charges would help ensure cost recovery. No such evidence of declining residential revenues exists in this docket. In addition, the Commission noted further that the 80% alternative "arguably decreases any disincentive AIU may perceive to implementing gas efficiency programs." This rationale was supplied by the Commission at a time when Ameren's gas efficiency program was voluntary, prior to the General Assembly's enactment of Section 8-104 of the Act, which mandates gas utility-provision of efficiency programs. Therefore, the AG argues the notion that any disincentive to the promotion of efficiency programs is required in utility rate design no longer applies.

Finally, the AG contends that the Commission specifically noted in the Nicor decision relied upon by the Utilities, that the reason the customer charge was being increased to recover 80% of costs through the customer charge was to be consistent with the Ameren decision. In addition, the Commission further noted in that docket:

> The Commission notes, as we did in our prior Ameren decision (Docket No. 07-0585 Cons., at 238), that, on average, the combination of increasing the fixed customer charge and decreasing the volumetric charges for fixed cost recovery is essentially a revenue neutral exercise. Staff apparently believes this rate structure would create an intra-class subsidy within Rate 1, whereby smaller customers would subsidize larger customers within the class. However, as stated in the Gas Distribution Rate Design Manual prepared by NARUC, rate classes should be defined

> —according to certain characteristics which are common to all members of the class. These characteristics can include size or load factors. To the extent that the Rate 1 residential class of customers may contain identifiable groups of customers that are not homogenous in their consumption or demand characteristics, the company should provide the Rate 1 customer, billing determinant information and any other statistical information necessary for Staff, the Company and any interested intervenors can to propose changes in the next rate case.

Northern Illinois Gas Company – Proposed Increase in Rates, Order of March 25, 2009 at 90. The AG states that this quote demonstrates that the Commission had no evidence that intra-class subsidies among residential users existed, and specifically requested an analysis of such subsidies in a next rate case. However, no rate case has been filed by Nicor since that 2009 decision. The AG maintains that in the instant case, we know that decreasing volumetric charges when customer charges are increased is not a symmetrical, revenue neutral price change. The AG argues the march toward ever increasing cost recovery in the residential customer charge has significant deleterious impacts on low-usage customers and creates inequitable cross-subsidies between low- and high-usage customers. The evidence in this docket shows that significant increases in customer charges lead to significant cross-subsidies of high users of natural gas by the Companies' lowest users, as noted above. The AG concludes that simply put, the facts that drove the Commission to significantly increase the customer charges of Ameren and Nicor ratepayers either no longer apply or are specifically contradicted by the evidence in this docket.

In light of these facts, the AG recommends that the Commission adopt Mr. Rubin's proposal.

CUB-City

CUB-City note that the usage and demand characteristics of the residential heating class are vastly different from those of the non-heating class. The heating class is not homogenous. In fact, it contains a considerable diversity in home sizes. AG Ex. 3.09. CUB-City find the utilities' rate proposals are largely driven by a desire for certainty of recovery, rather than an appropriate and fair allocation of costs caused by this class, and their proposals do not recognize the diversity of the class usage.

CUB-City note that AG witness Rubin testified that it is improper to recover demand-related costs on a per-customer basis except in the rare case when a customer class is relatively homogeneous, as with the Companies' non-heating customer classes. Companies witness Grace claims that, "[w]hile not yet completely matching fixed costs and fixed charges, Peoples Gas' [and North Shore's] proposed rates will provide more balance than its present rates and will send more appropriate price signals to customers about the fixed costs underlying its delivery service." NS-PGL Ex. 12.0 at 10. In CUB-

City's view, this perspective, illustrates the utilities' failure to recognize the large disparities within the heating class and to appropriately design rates that recover the substantial demand-related costs that the utilities incur to serve heating customers.

CUB-City explain that Companies witness Grace proposes recovery of 80% of non-storage related fixed costs through the customer charge, with all remaining non-storage costs being recovered through a flat distribution charge for each utility. NS-PGL Ex. 32.0, 23. Using the Companies' rate increase request numbers from its rebuttal testimony for Peoples Gas, this proposal would increase the heating customer charge from its current level of $21.89 per month to $37.58 per month, including a distribution charge of 10.0566¢ per therm for all gas consumed (compared to the existing declining block rate of 25.963¢ per therm for the first 50 therms per month and 11.806¢ per therm for usage above 50 therms per month). NS-PGL Ex. 32.4. For North Shore, using revenue requirement numbers from rebuttal testimony, the utility's primary proposal would increase the heating customer charge from its current level of $21.92 per month to $28.83 per month, with a distribution charge of 6.699¢ per therm for all gas consumed (compared to the existing rate of 16.942¢ per therm for the first 50 therms per month and 5.032¢ per therm for usage above 50 therms per month). NS-PGL Ex. 32.1. CUB-City further note that in direct testimony, the utilities also proposed a second rate design proposal that would set the heating customer charge for Peoples Gas heating customers to $44.69 per month and for North Shore heating customers to $36.04 per month, with no distribution charge, based on the original revenue requirement request. AG Ex. 3.03.

CUB-City maintain that the Companies' rate design proposals for residential heating customers neither recognize nor appropriately recover the substantial demand-related costs that the Companies incur to serve heating customers. AG Ex. 3.0R at 22. For example, North Shore's demand-related cost is approximately 35% higher than its proposed rate per therm. AG Ex. 3.0R at 23, citing AG Ex. 3.10, lines 9-13. CUB-City point out that Peoples Gas' demand-related cost is approximately 29% higher than its proposed rate per therm. AG Ex. 3.0R at 19, citing AG Ex. 3.08, lines 9-13. CUB-City argue the end results of a rate design that misallocates demand-related costs to the fixed monthly customer charge are (1) that low-use customers pay more than the cost to serve them and (2) that high-use customers pay less than the cost to serve them. CUB-City maintain this failure to recognize the demand cost disparity shown by the ECOSS perpetuates cross-subsidization within the heating class. This is the same flaw that led to North Shore's existing rates greatly over-recovering costs from non-heating customers, according to CUB-City. AG Ex. 3.0R at 22.

CUB-City note that Mr. Rubin calculated proposed rates using the AG's recommended revenue requirement from rebuttal testimony. However, CUB-City states that the actual rates will result from the adoption of any rate design in this proceeding will necessarily be dictated by the revenue requirement ultimately adopted. CUB-City note that the AG's recommended rates can easily be scaled to reflect the revenue requirement found by the Commission.

CUB-City state that the residential rate structure proposed by Mr. Rubin appropriately recognizes the difference between customer costs and demand related costs. The rate structure allocates costs appropriately, avoiding the significant cross-subsidization that has occurred as a result of ignoring the lack of homogeneity in the residential class and continuing the unwarranted movement toward an SFV rate. CUB-City aver that Mr. Rubin has designed rates that are cost-based and that do not cause significant cross-subsidies. CUB-City argues the key is recovering demand-related costs on a per therm basis rather than on a per-customer basis. CUB-City, therefore, recommend that the Commission adopt the rate design recommended by AG witness Rubin.

Commission Analysis and Conclusions

The Utilities propose to continue recovering storage-related fixed costs through Rider SSC. The Utilities also propose for S.C.1 HTG, recovery of non-storage related fixed costs through the customer charge with recovery of all remaining non-storage related fixed costs through a single flat distribution charge. Underlying the Utilities' proposal is the argument that all non-storage related costs at issue here are fixed costs.

Staff does not object to the proposed recovery of storage-related fixed costs through Rider SSC. Additionally, Staff does not object to the proposal to move from a declining block distribution charge to a single flat distribution charge. Staff, however, proposes to increase the recovery of non-storage related fixed costs from 67% to 68% through the distribution charges for North Shore and from 54% to 61% for Peoples Gas.

The AG also does not object to the proposed recovery of storage-related fixed costs through Rider SSC. For S.C.1 HTG customers, the AG proposes that the Utilities recover 75% customer related distribution costs through the customer charge and that the remaining 25% of those costs be recovered through the first block distribution charge. The AG takes issue with the Utilities' assertion that all non-storage related costs at issue here are fixed costs.

As discussed previously in this Order, as a general proposition, the Commission continues to believe that more fixed costs should be recovered through fixed charges when appropriate. The Commission has approved the recovery of 80% of fixed costs through fixed charges in other natural gas proceedings, however, the Commission believes that in this instance, the record evidence does not support such a conclusion. It is clear that the bifurcation of the S.C. No. 1 class will produce a decrease for the non-heating class even with the increase in fixed cost recovery proposed by Staff and the Utilities. However, this is not the case for the heating class. In the interest of promoting the principles of gradualism, rate continuity, and rate understandability, the Commission believes it is necessary to observe the effects of the bifurcation on the heating class before further increasing the percentage of recovery of non-storage fixed costs recovered through the customers charge. Having considered all of the evidence in the record, the Commission finds that Staff's proposed rate design for S.C.1 HTG is reasonable and should be adopted.

The Commission also notes that, generally speaking, the AG witness' proposals are inconsistent with the Commission's policy of increasing fixed cost recovery through fixed charges on a gradual basis. Additionally, the basis for the AG's proposed distribution charges is not entirely clear to the Commission.

c. Service Classification Nos. 1 and 2, Alternative Conditional Straight Fixed Variable Rate Design

Utilities

Utilities witness Ms. Grace explained that the Utilities propose that, under specified circumstances, the S.C. Nos. 1 NH, 1 HTG, and 2 rate designs would be replaced by SFV rate designs and charges that the Commission sets in this proceeding based on the revenue requirements it adopts in this proceeding. NS Ex. 12.0 Rev. at 17; PGL Ex. 12.0 Rev. at 17. Under SFV rate design, all fixed costs related to gas distribution service (those that do not vary with customer usage) are recovered through fixed charges, such as a monthly customer charge, and those costs that vary with customer usage are recovered through a volumetric charge, such as a distribution charge. NS Ex. 12.0 Rev. at 16; PGL Ex. 12.0 Rev. at 17. Ms. Grace testified that the Utilities included language in S.C. Nos. 1 and 2 to define the circumstances under which SFV rates would take effect and the specific rates that would take effect. The two specific events that would trigger the implementation of the SFV rates are (1) a Court finds or holds that the Commission lacks or lacked authority to approve Rider VBA, or (2) Rider VBA is otherwise not permitted to remain in effect by action of the Commission. Were either event to occur, then the SFV rates would take effect 90 days after the date of such Court or Commission action, or such other date as ordered by such Court or the Commission. Although the tariff would include the charges and the triggering events such that customers are on notice of the new rates, the Utilities would also provide prior notice to customers of the triggering event and the SFV rates. That additional notice, if possible, would be 30 days. NS-PGL Ex. 48.0 Rev. at 10-11.

Ms. Grace stated that the Utilities' decoupling mechanisms are on appeal. She opined that if the Illinois Appellate Court were to reverse the Commission's approval of decoupling, customer charges recovering anything less than 100% of fixed costs would not result in the level of decoupling approved by the Commission in the 2011 rate cases. NS Ex. 12.0 Rev. at 16-17; PGL Ex. 12.0 Rev. at 16-17.

The Utilities state that arguments that their alternative SFV rate design is unlawful rest on contentions that, contrary to Section 9-201 of the Act, the Utilities would (1) place new rates into effect and (2) do so without prior notice. The Utilities state that the flaw in these arguments is that they rely on mischaracterizations about the proposal. The Utilities explain that in their primary proposal, they have proposed specific rate designs as discussed herein, including customer charges and distribution charges, for their S.C. Nos. 1 and 2. This primary proposal presumes that Rider VBA remains in effect and, as with the rates that the Commission approved in *Peoples Gas 2011*, provide less than full recovery of fixed costs through fixed charges. Additionally and alternatively, in their alternative proposal, the Utilities have proposed specific rate

designs and charges that would take effect if Rider VBA were not in effect and would replace the charges developed under the primary proposal. The Utilities' proposal is that the Commission approve the primary proposal and the alternative proposal. NS Ex. 12.0 at 17, 21; NS Exs. 12.4, 12.5; PGL Ex. 12.0 at 17, 21; PGL Exs. 12.4, 12.5; NS-PGL Exs. 32.1, 32.2, 32.3, 32.4; NS-PGL Ex. 48.0 Rev. at 10-11.

The Utilities state that the approved tariffs would show both sets of charges and their effective dates, either in terms of the effective date stated on the sheet for the charges determined under the primary proposal or the precisely defined events described in the tariff sheet that would result in the charges determined under the alternative proposal taking effect and replacing the first set of rates. Only one set of rates would be in effect at any time.

The Utilities contrasted these facts with the situation in *Citizens Utility Board v. Illinois Commerce Comm'n.*, 275 Ill. App. 3d 329 (1st Dist. 1995) ("*CUB*"). The Utilities state that in that case, the Court found that a ComEd tariff ("Rate CS") permitting the utility to negotiate rates with a customer as long as the rates exceeded incremental costs was unlawful. The Court's concern was that the tariff contained no charges. Until the utility negotiated a contract, there would be no charges under the tariff. The tariff granted the utility the right to set rates in the future. *CUB* at 339. In contrast, in this matter, the Utilities filed a tariff that includes specific charges. One set of filed and public tariff charges will take effect with the compliance filing. The alternative set of filed and public tariff charges will take effect upon the occurrence of specific events. The infirmity that the Court identified with Rate CS does not exist in this matter. The customers' notice of the alternative charges is identical to the notice of the first set of rates. The Utilities filed this case under Section 9-201 of the Act. The filed tariffs show the primary proposal and the alternative proposal. The Utilities' testimony described the derivation of those charges. Therefore, the Utilities argue, they complied with the Section 9-201 notice requirements applicable to this filing. NS Ex. 12.0 Rev. at 5; PGL Ex. 12.0 Rev. at 5; NS-PGL Ex. 32.17.

The Utilities state that the AG's argument that it is somehow inappropriate that the alternative proposal charges be based on the same revenue requirement as approved in this case because "a utility's expenses and revenues are dynamic ever-changing" (AG Init. Br. at 120) is puzzling. The AG's observation that costs and revenues are ever-changing is axiomatic. A switch to SFV rates derived from the Commission-approved revenue requirement and set forth in the compliance filing in this proceeding serves no different function than the Utilities' primary proposal – rates that create an opportunity for the Utilities to recover their approved revenue requirements.

The Utilities dispute the AG's claim that the proposal is contrary to the test year rule. The test year for all the Utilities' proposed rates is 2013. The proposal does not circumvent the test year requirements. The Utilities simply presented two ways of designing rates using the same revenue requirements.

The Utilities also take issue with Staff's policy argument for several reasons.

First, Staff's concern about the differing impacts of decoupling *versus* SFV on low and high use customers (Staff Init. Br. at 108-109) is addressed by the Utilities' bifurcation proposal. The Utilities' proposed primary and alternative rate designs are designed to recover the same revenue requirements from customers. The bifurcation increases the homogeneity of customer classes within S.C. No. 1 and, thus, addresses concerns about the relatively different impact on low *versus* high use customers.

Second, Staff's proposed increase in fixed cost recovery through fixed charges is minimal, remains far below the modified SFV rate designs the Commission approved for Nicor Gas and Ameren (80% fixed cost recovery in fixed charges) and is far below the full decoupling represented by Rider VBA.

Third, Staff is correct that the Utilities may file a rate case to address a change in circumstances, but that is not a reason to avoid addressing the matter in the instant rate case. Moreover, rates from that filing would not take effect for eleven months, creating an unnecessary lag between the Court or Commission action invalidating Rider VBA and the implementation of appropriate rate designs.

Fourth, the fact that the Utilities are using a forecast test year with forecast customer demand is irrelevant. The forecast assumes normal weather. NS Ex. 4.0 at 10; PGL Ex. 4.0 at 10. While more frequent rate cases and a future test year would provide the Utilities timelier cost recovery, that alone will not address the vagaries that occur between rate cases such as weather, gas prices and changes in the economy. Moreover, these factors, which lie outside the Utilities' and customers' control, can lead to over- as well as under-recovery of costs. NS-PGL Ex. 32.0 at 36. The best and most accurate forecast will not prevent over- or under-recovery of a utility's revenue requirement if weather is colder or warmer than normal.

Fifth, possible customer confusion is not a reason to reject the Utilities' proposal. For example, in the 2009 rate cases, the Commission approved Rider FCA, Franchise Cost Adjustment, for North Shore. Due to the nature of the rider and the timing of the implementation of new rates arising from the rate proceeding, North Shore had to implement new rates effective shortly after the compliance filing and again in mid-year after rates from the rider went into effect. Consequently, North Shore's tariffs included two sets of rates that would become effective at different times. The Utilities are not aware of any customer confusion that arose as a result. NS-PGL Ex. 32.0 at 37-38. In any event, to address Staff's concern, the Utilities added an additional form of notice. NS-PGL Ex. 48.0 Rev. at 11.

Sixth, Staff is correct that it is speculative whether Rider VBA will remain in effect, but the pending appeal and the AG's and CUB-City's claims in the instant proceeding that Rider VBA is unlawful are facts that lend uncertainty to the continued viability of Rider VBA.

Seventh, if the Commission is concerned about providing an SFV rate design (100% recovery of fixed costs in fixed charges), then the Utilities proposed modified SFV (80% recovery of fixed costs through fixed charges), which is the rate design that the Commission approved for Ameren and Nicor Gas, as an alternative. NS-PGL Ex. 32.0 at 39. The Utilities note that Staff finds the 80% recovery to be an acceptable level if the Commission decides to approve the Utilities' SFV proposal. Staff Ex. 8.0 at 18.

The Utilities conclude that their SFV rate design is a reasonable means of addressing the uncertainly associated with Rider VBA. Staff's and the AG's opposition, if endorsed by the Commission, would expose the Utilities and customers to that which is unnecessary -- either over- or under-recovery of the distribution revenue requirement, which is contrary to the Commission's approval of full decoupling (Rider VBA) in the 2007 rate cases and its affirmation in making decoupling permanent in the 2011 rate cases.

Staff

Staff notes that the Companies propose 100% SFV rates for S.C. No. 1 Small Residential HTG, NH, and S.C. No. 2 General Service classes that would be placed in the rate tariffs as a place holder in the event Rider VBA is no longer in effect because of a third party's action. PGL Ex. 1.0 at 14; NS Ex. 1.0 at 13. The Companies state that the SFV rate design would reflect a fixed monthly customer charge and no volumetric distribution charge. PGL Ex. 12.0 Rev. at 17, 21; NS Ex. 12.0 Rev. at 16-17, 21. The Companies propose that if Rider VBA is not in effect then, at a minimum, if the Commission does not believe 100% SFV rates should be implemented, SFV rates recovering 80% of non-storage related fixed costs, along with a flat distribution charge should be implemented for S.C. No. 1 HTG, S.C. No. 1 NH, and S.C. No. 2. The Companies also propose that the 80% fixed cost recovery for S.C. No. 2 be applicable for each meter class. NS-PGL Ex. 32.0 at 15, 20, 25, 29. Staff further notes that Companies witness Grace argued that if the Illinois Appellate Court were to reverse the Commission's Order with regard to Rider VBA, customer charges recovering anything less than 100% of fixed costs would not result in the level of decoupling approved by the Commission in Docket No. 11-0280/11-0281 (Cons.). PGL Ex. 12.0 Rev. at 16; NS Ex. 12.0 Rev. at 16.

Staff urges the Commission to reject the Companies' proposal for several reasons. First, as demonstrated in Staff's direct testimony, Rider VBA and SFV rates are not equivalent substitutes for one another because they recover fixed costs in different proportions from different customers resulting in different rate impacts on customers. Rider VBA recovers any under or over recovery of fixed costs on a per therm basis. SFV rates would recover fixed costs on a per customer basis, which would affect small use customers greater than larger use customers. Staff Ex. 8.0 at 10, 15.

Second, even if the Illinois Appellate Court reverses the Commission's Order in Docket Nos. 11-0280/11-0281 (Cons.) Staff is still proposing greater fixed cost recovery through fixed charges. If the Commission believes greater fixed cost recovery is

warranted, then Staff's proposed non-SFV rates would meet that requirement in a way that is more consistent with prior Commission orders and that considers gradualism and conservation.

Third, if events occur that lead the Companies to believe that a different rate structure would be more appropriate, the Companies are able to file rate cases when they deem it necessary to do so. In fact, according to the Companies' own testimony, Peoples Gas and North Shore are currently required to file biennial rate proceedings in 2014 and 2016 under Section 9-220(h-1) of the Act. Staff Ex. 8.0 at 13.

Fourth, the Companies used customer demand forecasts for the 2013 test year which should minimize some of the Companies' concerns about adequate cost recovery. In fact, Companies witness Kevin R. Kuse testified that the Companies have used this same model in the past three rate cases and the model has performed well historically. *Id.* At 17.

Fifth, having two rates in place will cause confusion for ratepayers or anyone else examining the tariff books. Tariffs are confusing enough for typical customers without presenting two sets of rates, one of which is not actually in effect. The Companies' proposal to present two different rates for the same service, one of which, the proposed SFV rate, takes two separate paragraphs to explain and has no effective date, would be very confusing to customers. It is in the best interest of the Commission and customers to have rate tariffs that are, to the greatest extent possible, easy to understand. In fact, the Act indicates that one of the goals and objectives of regulation is to ensure "the fair treatment of consumers and investors in order that…the application of rates is based upon public understandability and acceptance of the reasonableness of the rate structure and level." 220 ILCS 5/1-102(d)(ii). Including two rates on a tariff sheet whereby one of the rates will become effective only if a court determines that the other rate is illegal is not only confusing but premature. In fact, there is no known effective date in the Companies' proposed tariff language. Even if Rider VBA is not allowed by the court to continue, there may be legal disputes over what the correct effective date of the new customer charges and distribution charges should be. Staff Ex. 17.0 at 11-12.

Sixth, Rider VBA is still in effect and it is speculative as to whether it will be overturned.

Finally, the Commission has already declined to approve 100% fixed cost recovery through a fixed charge. In fact, the Commission explained why it is important to leave a portion of fixed costs to be recovered through the volumetric rate:

> The Commission does not at this time approve recovery of all fixed costs in the monthly charges for two reasons. First, it is expected that leaving a portion of fixed costs to be recovered through the volumetric rate will encourage AIU to see ways to improve efficiency and otherwise cut costs. Second, as the number of AIU's customers grows, AIU should experience growing revenue. If all of

> its fixed costs were recovered through the monthly charge, AIU may arguably over-recover its fixed costs through the monthly charge.

Order, Docket No. 07-0585 et al. (Cons.), September 24, 2008 at 237.

Staff concludes that this passage shows the Commission was clear that it did not want 100% fixed cost recovery through a fixed charge.

Staff also argues that if the Commission decides to approve a SFV rate design as a back up in the event that Rider VBA is overturned, which it should not, the Commission should ensure that the fixed cost recovery does not exceed the 80% approved for Ameren and Nicor. The same reasons the Commission gave for not allowing Ameren and Nicor to have 100% fixed cost recovery also apply to Peoples Gas and North Shore. Additionally, Staff maintains that the Commission should proceed gradually and cautiously in the movement towards greater fixed cost recovery to ensure that basic rate objectives are carefully taken into consideration. Staff Ex. 8. at 18.

Staff further argues that even if the Commission rejects its arguments against the Companies' conditional tariff proposal which it should not, the Companies' proposal should be rejected as a matter of law. It is Staff's view that the Companies' conditional tariff proposals are inconsistent with Section 9-201 of the Act. Section 9-201(a) provides in part that:

> Unless the Commission otherwise orders, and except as otherwise provided in this Section, no change shall be made by any public utility in any rate or other charge or classification, or in any rule, regulation, practice or contract relating to or affecting any rate or other charge, classification or service, or in any privilege or facility, except after 45 days' notice to the Commission and to the public as herein provided. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules or supplements stating plainly the change or changes to be made in the schedule or schedules then in force, *and the time when the change or changes will go into effect*, and by publication in a newspaper of general circulation or such other notice to persons affected by such change as may be prescribed by rule of the Commission. The Commission, for good cause shown, may allow changes without requiring the 45 days' notice herein provided for, by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

220 ILCS 5/9-201(a) (emphasis added). Under the Companies' proposal, the tariff only takes effect, if it ever does, at some unknown date in time depending on events outside the Commission's control. This proposed conditional tariff is contrary to the plain language of Section 9-201(a) that a tariff must state "plainly the change or changes to be made in the schedule or schedules then in force, and *the time when the change or changes will go into effect.*" 220 ILCS 5/9-201(a) (emphasis added). Staff reasons that

since no one knows when the conditional tariff will take effect, if it ever does, the conditional tariff fails to comply with the requirement of Section 9-201(a) that an effective date be provided in the tariff. Accordingly, Staff contends that the conditional proposed tariffs of North Shore and Peoples Gas should be rejected as a matter of law.

AG

The AG notes that in the Utilities' 2011 rate case, the Commission approved the Utilities' request for the permanent adoption of Rider VBA. Rider VBA permits the Companies to assess extra surcharges when the actual usage of customers in rate classes 1 and 2 falls below the forecasted usage levels for those classes and credits when usage for those customer groups exceeds forecasted levels. Rider VBA is designed to *guarantee* that the Companies recover the revenue requirement established in the Companies' most recent rate case for the residential and small commercial customer classes. The AG asserts that this revenue guarantee persists regardless of whether the revenue requirement established in the most recent rate case is actually needed or appropriate going forward, and in spite of the fact that a utility's expenses and revenues are dynamic and ever-changing.

The AG also observes that the Utilities presented the testimony of Mr. Schott and Ms. Grace, who testified that both North Shore and Peoples Gas were proposing that the Commission adopt not only a specific rate design proposal for residential heating and non-heating customers, but also a conditional SFV tariff that would take effect should the existing Rider VBA terminate due to some third-party action, including an appellate court decision declaring the tariff unlawful, or action by the Commission. Under this proposal, NS-PGL asks the Commission to approve (1) its proposed rate design for heating and non-heating customers (which would reflect a decrease in the monthly customer charge for non-heating customers and an increase in the monthly customer charge for heating customers, and a revised flat per-therm distribution charge that would be the same for both heating and non-heating customers); and (2) a conditional 100% SFV tariff that would take effect if and when Rider VBA is no longer in effect under which the Companies' residential heating and non-heating customers would receive customer bills with a rate design that would reflect a fixed monthly customer charge and no volumetric distribution charge. PGL Ex. 12.0 at 10-11.

The AG argues that the Commission should reject the Utilities' proposed conditional SFV tariff because it is unlawful. The AG asserts that Section 9-201 of the Act establishes the framework under which utilities may propose a change in rates, and the Commission may authorize such changes. According to the AG, the Utilities' request that the Commission approve two residential service tariffs, one that would take effect as normally occurs within two days of the end of the 11-month suspension period in this case under Section 9-201(b) of the Act, and a second tariff that would possibly take effect at some unknown date in time, depending on events outside of the Utilities' and the Commission's control, is contrary to the requirements set forth in Section 9-201(a) of the Act that the published tariff must state "plainly the change or changes to be made in the schedule or schedules then in force, *and the time when the change or*

changes will go into effect." 220 ILCS 5/9-201(a) (emphasis added). The AG argues that because neither the Utilities nor the ratepayers who must pay the 100% SFV rates have any idea when the conditional rate change would occur, it is impossible for the NS-PGL tariff to comply with Section 9-201(a)'s mandate that an effective date be provided. The Companies' proposed 90-day and 30-day "notice" language, added in Ms. Grace's surrebuttal testimony, does not remedy this legal flaw. NS-PGL Ex. 48.0 at 10-11. The fact remains, neither the Companies' customers nor the Commission have any idea when such a tariff change would take effect.

In addition, the AG asserts that the Companies' conditional SFV tariff is inconsistent with the requirement that changes in rates be set based on a test year. 83 Ill.Admin.Code Part 285. *BPI II* at 146 Ill. 2d 175, 238. In order to accurately determine the utility's revenue requirement, the Commission established filing requirements under which a utility must present its rate data in accordance with a proposed one-year test rule. Section 287.20 of the Commission's rules provides that a utility may, at its option, propose either an historical or a future test year. 83 Ill.Admin.Code Part 287.20. The purpose of the test-year rule is to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one year with high expense data from a different year. *Business and Professional People for the Public Interest v. Illinois Commerce Comm'n ,* 136 Ill.2d 192, 219, 555 N.E.2d 693 (1989) ("*BPI I").*

The AG argues that the Utilities' conditional SFV tariff by its terms is contrary to the test year rule because it would establish a new rate at an unknown date in the future based on a revenue requirement approved in this case. The conditional SFV tariff is indeed premised on the notion that the revenue requirement set by the Commission in this case will be the appropriate revenue requirement at some unidentified point in the future.

Moreover, the AG notes that Illinois courts have held that once a rate order is set aside on appeal, the utility cannot continue to benefit from what has been determined to be unlawful portions of a rate increase. *Independent Voters of Illinois v. Illinois Commerce Comm'n,* 117 Ill.2d 90, 104 (1987) ("*IVI")*. The judgment of an appellate court is final upon all questions decided, and if the cause is remanded, the (Commission) can take only such action that conforms to the judgment of the reviewing court. *Id.* at 102. The AG posits that the Companies' 100% SFV rate design proposal, which is specifically tied to a possible Appellate Court reversal of Rider VBA, has the effect of subverting the authority of the Illinois Appellate Court by implementing a conditional rate designed to achieve the same goal as a tariff that may be declared unlawful by the Appellate Court. Neither the Commission nor the parties to this docket know how the Second District Appellate Court will rule on Rider VBA or what the Court will say about the notion of guaranteeing the recovery of so-called "fixed costs," the principle upon which Rider VBA is based. But should the appellate court in the pending Rider VBA appeal reverse the Commission's approval of Rider VBA and the mandate is issued by the Appellate Court, the Commission is obliged to respect that decision and any remand instructions that may follow. The Commission's goal in rate setting should not be attempting to predict or circumvent a ruling of the Appellate Court. However, the

AG argues the Utilities conditional 100% SFV tariff and the proposal to adopt it as a conditional tariff are designed to achieve that goal.

Finally, the AG states that the theory behind public utility regulation is that the Commission should fix rates that "might properly be supposed to result from free competition." *State Public Utilities Comm'n v. Springfield Gas & Electric Co.,* 291 Ill. 209, 218, 125 N.E. 891, 896 (1919). However, the AG asserts that the Utilities' conditional 100% SFV proposal essentially seeks to ensure recovery of costs regardless of customer usage of the delivery service network, contrary to the Illinois Supreme Court's declaration that utility rates should mirror that which would exist in the competitive marketplace. The Utilities' view that a revenue requirement must be guaranteed is a radical concept – indeed one that is now being examined by the Appellate Court -- that should not be set into motion at some unnamed point in time through the consideration and adoption by the Commission of the Utilities' conditional SFV tariff. The AG argues that the new 100% SFV rates would conceivably come as quite a shock to customers if, for example, the significantly higher customer charge appeared on a heating customer's bill in the summer months.

The AG states that the Companies always retain the option to file a request under Section 9-201 if they feel their current rates are not recovering their costs. The AG concludes that requesting Commission approval of a tariff that seeks to ensure a revenue requirement established in this case into the future notwithstanding an appellate reversal of a certain tariff (Rider VBA) runs contrary to the statutory vehicle established by the General Assembly for utilities to seek rate increases and such a request must therefore be rejected by the Commission.

For these reasons, the AG maintains that the Commission should reject the Utilities' proposed conditional SFV tariff.

CUB-City

CUB-City recommend that the Companies' conditional tariff be rejected because it violates the requirement in Section 9-102(a) of the Act that tariffs must include a time when the change will go into effect and notice of such must be published. CUB-City argue that the time at which the SFV tariff will take effect is simply not specific enough to meet this requirements. The triggering events contained in the Companies' original proposed tariff language allowed the conditional SFV tariff to go into effect on the action of any third party. In response to criticism from Staff, CUB-City and the AG, however, the Companies revised their proposed tariff language to limit the triggering events to a court holding or "action of the Commission:"

> If a court finds or holds that the Commission lacks or lacked authority to approve Rider VBA of this rate schedule or Rider VBA of this rate schedule is otherwise not permitted to remain in effect by action of the Commission, then 90 days on and after the date of such court or Commission action, or

> such other date as ordered by such court or the Commission, the monthly Customer Charge shall be $xx.xx for Non-Heating Customers and $xx.xx for Heating Customers.
>
> If a court finds or holds that the Commission lacks or lacked authority to approve Rider VBA of this rate schedule or Rider VBA of this rate schedule is otherwise not permitted to remain in effect by action of the Commission, then 90 days on and after the date of such court or Commission action, or such other date as ordered by such court or the Commission, the Distribution Charge shall be x.xx cents per therm for Non-Heating Customers and xx.xx cents per therm for Heating Customers, for all gas delivered in any month.
>
> Within the later of 30 days of such court or Commission action or the date on which the Company knows the effective date, the Company shall revise this tariff sheet to show the effective date of the change in rates and file it with the Commission. The Company shall also provide written notice to customers prior to the date that such rates go into effect, and, if possible given the effective date ordered by the court or other body, shall provide at least 30 days' prior notice.

NS-PGL Ex. 48.0 Rev. at 10-11.

CUB-City maintain that the provisional nature of the tariff, and its dependence on actions by third parties – even as revised, render this tariff unlawful. It does not meet the requirements of 9-201 of the Act. Additionally, the Commission's lack of knowledge of the events that could surround Rider VBA no longer being in effect at some point in the future make it impossible for the parties and the Commission to give the required consideration to the SFV tariff.

Furthermore, CUB-City state that the confusion shown by the Companies' tariff expert on how their proposed conditional tariff would become effective should eliminate it from any serious consideration by the Commission. As proposed, and as interpreted by the Companies, CUB-City aver implementation of the tariff will likely prove arbitrary. For example, despite last minute changes in the proposed language governing notification procedures, the Companies could not explain when the tariff would become effective in several plausible scenarios, which makes notice of the effective date, as required by statute, impossible. Tr. at 800-803; 220 ILCS 5.9-201(a). CUB-City point out that if PGL's expert cannot explain how the trigger making the tariff effective would work, the Commission (and especially customers) cannot be asked to do what PGL could not.

CUB-City assert that the Commission, utility customers, and the Companies themselves cannot lawfully be subject to unavoidable confusion and arbitrary implementation of the conditional tariff. The proposed conditional tariff is unnecessary, unwise, and unlawful. For these and other reasons presented in the record, CUB-City recommend the tariff be rejected.

Commission Analysis and Conclusions

The Utilities propose a conditional SFV tariff for S.C. No. 1 Small Residential HTG, NH, and S.C. No. 2 General Service classes which would be implemented in the event that Rider VBA is no longer in effect because (1) a Court finds or holds that the Commission lacks or lacked authority to approve Rider VBA, or (2) Rider VBA is otherwise not permitted to remain in effect by action of the Commission. The Commission finds that the Utilities' proposal is now moot in light of the Illinois Appellate Court's recent decision issued on March 29, 2013 affirming the Commission's adoption of Rider VBA on a permanent basis in the Utilities' 2011 rate cases. Hence, the Court's recent decision addresses the Utilities' concern about the possible reversal of Rider VBA. Additionally, as stated elsewhere in this Order, the Commission continues to believe that Rider VBA is a sound rate design policy that should remain in place permanently as approved by the Commission in the 2011 rate cases and recently affirmed by the Illinois Appellate Court.

D. Fixed Cost Recovery and Rider VBA

Utilities

The Utilities explain that their primary proposal is that Rider VBA, as approved in the 2011 rate cases, remain in effect for S.C. Nos. 1 and 2 and that fixed cost recovery through fixed charges increase somewhat for these service classes. As discussed in Section IX.C.2.c, *supra*, they also propose that under certain circumstances, if Rider VBA were no longer in effect, that SFV rates would take effect.

Utilities witness Ms. Grace stated that, even if Rider VBA remains in effect, gradually increasing fixed cost recovery through fixed charges is a sound rate design and consistent with Commission policy. Ms. Grace explained that this is true for several reasons. First, Rider VBA is on appeal. With the risk that the Court may reverse the Commission's approval of full decoupling, more substantial movement to fixed cost recovery through fixed charges is appropriate. Second, the 80% fixed cost recovery proposed for S.C. No. 1 would be consistent with the partial decoupling approved for Ameren and Nicor Gas and would leave a reasonable amount of fixed costs that would be recovered through distribution charges, but still subject to the full decoupling approved under Rider VBA. Third, Ms. Grace stated that Staff witness Mr. Johnson is proposing to set the customer charge for North Shore's and Peoples Gas' S.C. No. 1 NH customers at 80% of fixed costs, leaving the Utilities' S.C. No. 1 HTG classes as the only small residential rate class with lesser fixed cost recovery among the state's large gas utilities if the Commission accepts Mr. Johnson's proposal. Ms. Grace further testified that absent decoupling under Rider VBA, a lower fixed cost recovery level

would effectively re-couple a large percentage of fixed cost recovery with the amount of gas that customers use, conflicting with prior Commission policy decisions supporting both increased fixed cost recovery and decoupling. NS-PGL Ex. 32.0 at 34-35.

The Utilities state that Staff's, AG's and CUB-City's arguments that it is inappropriate or radical for the Utilities to have "guaranteed" recovery of fixed costs are flawed. The guarantee that the parties discuss is nothing more than recovery of the approved revenue requirements. It is not a guarantee of profits or that the Utilities will earn their allowed rates of return. As the AG states in discussing the alternative SFV rate design, the Utilities' expenses are ever-changing. Rider VBA does not address those changing expenses. Thus, the Utilities argue that if their costs are higher than those included in the approved revenue requirements, Rider VBA does nothing to address those higher costs because Rider VBA is linked to the approved revenue requirement.

The Utilities assert that the notion that Rider VBA is unusual or radical or contrary to utility ratemaking is disproved by the prevalence of decoupling in its various forms throughout the country. Decoupling mechanisms, including forms such as SFV rates, rate stabilization mechanisms and weather normalization mechanisms exist in 35 states for 113 companies. NS-PGL Ex. 32.0 at 40. Decoupling is the norm in utility ratemaking according to the Utilities.

The Utilities maintain that any contentions that Rider VBA is unlawful are properly before an Illinois appellate court, and that Court is the proper forum for addressing these arguments. It is the Utilities' position that Rider VBA is lawful for all of the reasons stated by the Commission in the *Peoples Gas 2007* and *2011* Orders.

First, Rider VBA is not single issue ratemaking. The Utilities state that the decisions the AG cited are inapposite because Rider VBA is not a cost recovery mechanism. Rider VBA isolates no costs and poses none of the risks that concerned the courts in the cited cases. Rider VBA does not take into account costs other than those in the Commission-approved revenue requirements. For example, if the Utilities' actual fixed costs are greater than those the Commission used to set the revenue requirements, Rider VBA does not provide recovery of those higher costs. Rider VBA is essentially a mathematical adjustment to ensure that the Utilities neither over-nor under-recover from customers their Commission-approved distribution revenue requirement.

Second, Rider VBA is not retroactive ratemaking. The Utilities explain that Rider VBA does not change the rates that the Commission found to be just and reasonable. Its entire purpose is to true-up to the revenue requirements that the Commission approved and, thus, to the rates derived from those revenue requirements. Rider VBA is a true-up mechanism predicated on the assumption that the rates derived from the approved revenue requirements are correct and the Utilities should not over-or under-recover those revenue requirement amounts.

Third, the test year issue is essentially the same as addressed in Section IX.C.2.b, *supra*, in connection with SFV rates. The Utilities assert that the test year 2013 revenue requirements are the basis of Rider VBA calculations.

Finally, Rider VBA is not a "lost revenues" rider. The Utilities note that the Commission correctly found in the 2007 rate cases that "Rider VBA does not seek to recover lost profits." *Peoples Gas 2007* Order at 149. Adjustments occur, as with the mechanism approved in the 2007 rate cases, through the application of a mathematical formula (*Peoples Gas 2007* Order at 151) that is based on the Commission-approved revenue requirement.

Staff

Staff notes that the Companies are proposing to collect a greater portion of fixed costs through fixed charges such as the customer charge and administrative charges. PGL Ex. 12.0 Rev. at 10; NS Ex. 12.0 Rev. at 9. Staff also observes that the Commission's Orders addressing fixed cost recovery, namely the Commission's Orders in Docket Nos. 09-0166/09-0167 (Cons.), 11-0280/11-0281, 07-0588, 07-0589, and 07-0590 (Cons.), and 08-0363, appear to be moving towards greater fixed cost recovery through fixed charges. However, Staff opines that the Commission should proceed gradually and cautiously in the movement towards greater fixed cost recovery. Staff witness Johnson explained that if too much emphasis is placed on ensuring revenue requirements are met through higher fixed charges, other basic rate objectives will be inadvertently overshadowed. Staff Ex. 8.0 at 6-8. Staff notes that the Commission made it clear in the Ameren Order in Docket No. 07-0585 et al. (Cons.) that caution should be used when recovering greater fixed costs in rates in order to meet certain rate objectives such as encouraging efficiency and reduced costs. Additionally, the Commission expressed concern in the Ameren Order about the possibility that Ameren could possibly over-recover its revenue requirement if too many fixed costs were recovered through the monthly charge. *Id*. at11.

Staff challenges the Utilities' argument that a greater portion of fixed costs should be recovered through fixed charges because customer usage and sales may vary from the normal level of sales used to set rates leading to over as well as under recovery of costs. Staff points out that sales level would be expected to fluctuate for any business venture. However, Staff asserts that it does not believe the Commission's intent is to put rates in place for utilities so that a certain revenue requirement is guaranteed. Section 1-102(a)(i) of the Act states: "tariff rates for sale of various public utility services are authorized such that they accurately reflect the cost of delivering those services and <u>allow</u> utilities to recover the total costs prudently and reasonably incurred." (220 ILCS 5/1-102(a)(i)) Staff notes that in the Companies last rate case, the Commission's final order stated the following "[u]nder long established federal and Illinois constitutional law, and Illinois ratemaking law, a utility's rates must be set so as to <u>allow it the opportunity to obtain full recovery</u> of its prudent and reasonable costs of service, including its costs of capital. Final Order, January 10, 2012, Docket Nos. 11-0280/0281 (Cons.) at 5 (emphasis added). In addition, Staff argues that the Companies will not be adversely impacted if the Commission approves a smaller amount of fixed cost recovery through

fixed charges than the Companies' requested. If the Commission approves Staff's proposal, the Companies will still receive an increase in fixed cost recovery through fixed charges. Moreover, the Companies have historically filed rate cases when they believed their rates were inadequate to cover their costs and the Companies will be filing another rate case again in 2014 as required under Section 9-220(h-1) of the Act. Staff Ex. 17.0 at 15.

The AG and CUB-City argue that the Commission should order the Companies to terminate Rider VBA. AG IB at 138; CUB-City IB at 79. AG and CUB-City argue in part that Rider VBA is unlawful because it violates the Act's prohibition against retroactive ratemaking. AG IB at 135; CUB-City IB at 75-76. Staff notes that the Commission decided to move forward with Rider VBA on a permanent basis just over a year ago in Docket No. 11-0280/0281 (Cons.). Rider VBA was initially in place on a pilot basis following the Commission's decision in Docket Nos. 07-0241/0242 (Cons.). In Docket Nos. 11-0280/0281 (Cons.) the Commission after considering the evidence decided to direct the Companies to continue Rider VBA on a permanent basis. Order, Docket No. 11-0280/0281 (Cons.), January 10, 202 at 164. The Commission's order stated in part the following:

> The Commission agrees with Staff that Rider VBA has operated as the Commission intended. The annual reconciliation proceedings have disclosed no issues with the operation of the rider. The Commission also agrees with Staff and the Companies that Rider VBA stabilizes the Companies' revenues and ensures that the S.C. Nos. 1 and 2 customers neither over- nor under-pay the approved revenue requirements. While the Commission supports increased recovery of fixed costs through fixed charges, it prefers, at this time, decoupling rather than a switch to an SFV rate design. For these reasons the Commission is convinced that there has been a compelling and sufficient showing that a permanent Rider VBA is reasonable and justified. The Commission directs that Rider VBA shall continue on a permanent basis. Subject to that limitation, the Commission approves the tariff changes as set forth in NS-PGL Ex. 45.5 and NS-PGL Ex. 45.6 except for those which provide consideration for customer switching between S.C.2, S.C. 3, and S.C. 4

Id. AG and CUB-City acknowledge that the Commission's order in Docket Nos. 11-0280/0281 (Cons.) is currently under appeal in the Second District, Docket Nos. 2-12-0243 and 2-12-0349. AG IB at 130. Staff's understanding is that the only thing left as part of that appeal process is for the Second District Appellate Court to issue its decision.

Staff urges the Commission to wait on the Appellate Court's decision on Rider VBA and reject the AG's and CUB-City's recommendation to terminate Rider VBA in this proceeding. Staff reasons that if the Commission were to terminate Rider VBA as the AG and CUB-City argue, which it should not, the appeals in the Second District, Docket Nos. 2-12-0243 and 2-12-0349, would become moot and those appeals would

likely be dismissed. *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n*, 67 Ill. App.3d 616, 617 (1979). A case is moot where there is no existing controversy and nothing remains for the court to decide. An appellate court will not review a case for the sole purpose of establishing a precedent. *Phillips v. Board of Education* (1974), 23 Ill.App.3d 124, 318 N.E.2d 687. An exception to the rule is stated in *People ex rel. Wallace v. Labrenz* (1952), 411 Ill. 618, 104 N.E.2d 769, Cert. denied, 344 U.S. 824, 73 S.Ct. 24, 97 L.Ed. 642, for cases of great public concern if an authoritative determination is desirable and if there is a likelihood of a future recurrence of the question." In addition, if the Commission finds that Rider VBA should be terminated, the Companies will presumably appeal the Commission's decision which would add even more years of litigation in pursuit of the ultimate fundamental issue of whether Rider VBA is consistent with the law as the Commission determined it to be in Docket Nos. 11-0280/0281 (Cons.) and Docket Nos. 07-0241/0242 (Cons.). For these reasons, Staff recommends that the Commission reject the AG's and CUB-City's proposal that Rider VBA be terminated.

AG

The AG argues that the Commission should revisit its authorization of Rider VBA in light of the substantial evidence in this record repudiating the Companies' claim that all of its costs are fixed and as such the extraordinary means of ensuring cost recovery through Rider VBA is necessary.

Rider VBA is Neither Necessary Nor Equitable.

AG witness Rubin testified that the fundamental problem with Rider VBA is that it is based on the assumption that the utility is somehow entitled to recover a certain level of revenues from each customer class in order to recover its fixed costs. This represents a fundamental change in the relationship between a utility and its customers. Mr. Rubin noted that utilities have never been guaranteed the recovery of a certain amount of revenue from their customers. Instead, the ratemaking process provides the utility with an opportunity to earn a particular return based on a test-year estimate of the amount of services the utility will sell. Mr. Rubin explained that no utility customer is required to use a certain amount of the utility's service, and a customer is free to use none at all if it so desires. AG Ex. 3.0 at 26.

However, the AG argues that decoupling seeks to have customers collectively guarantee a certain level of sales to the utility – regardless of the many factors that may affect the amount that a utility actually sells, such as weather conditions, the community's financial circumstances, global energy concerns, appliance and equipment offerings in the marketplace, or the price and quality of the utility's service. Decoupling also shifts an extraordinary level of risk to customers, removes that risk from the utility, and could provide perverse incentives to the utility. *Id.* at 27-28.

The AG avers that Rider VBA provides perverse incentives that are inconsistent with the utility's obligation to serve customers under the Act. As one example, utilities would no longer have an incentive to ensure that it can reliably deliver gas on demand to customers. For example, Mr. Rubin posited, "What would happen to the Companies if

they failed to have enough gas in storage or did not properly maintain their systems, causing more outages?" *Id.* at 28. The AG asserts that normally that would mean that the Companies would earn less money than they could have otherwise because they would obviously not sell as much gas as they could have sold. However, under decoupling the Companies would simply collect less money today, but get to recover those lost earnings from customers tomorrow. The AG posits that decoupling removes the incentive to maintain a reliable system that is capable of meeting 100% of customers' demands for gas service. *Id.* at 28.

The AG asserts that taken to its logical conclusion, decoupling could actually encourage the Companies to divert gas to competitive customers (such as power plants) and away from captive customers. They would earn a margin on each sale to competitive customers and would recover (through the decoupling rider) the lost margin on unmade sales to captive customers. Mr. Rubin testified that he could not imagine a worse incentive structure for a natural gas utility. *Id.* at 29.

The AG contends that other problems are triggered by the existence of Rider VBA. At its heart, decoupling is based on the premise that it is the Commission's job to protect the utility from the vagaries of the marketplace and to safeguard the utility's investors from changes in customer demand. However, the fundamental purpose of regulation is to protect consumers from the unfettered market power of monopolists; not to protect the revenue stream or profit levels of those monopolists. *Id.* at 29.

The AG points out that in its Order in Docket No. 11-0280/11-0281, the Commission concluded:

> Some of the problems that Rider VBA was originally intended to protect the utilities from were the reality of fixed costs against a backdrop of a diminishing customer base and resulting revenue losses as well as revenue losses attributable to the implementation of aggressive energy efficiency programs. The reasons to continue Rider VBA are that it is a symmetrical and transparent formula for collecting the approved distribution revenue requirements -- not more or less -- from customers if the Commission chooses not to provide fully for recovery of fixed costs through fixed charges. There are however, additional benefits to ratepayers from Rider VBA. As Staff witness Dr. Brightwell indicated in his testimony, Rider VBA reduces the reliance on forecasting customers and usage to set rates. Staff Exhibit 6.0, pp. 4-5. The forecasts are inevitably incorrect each year, and they are only correct on average. Thus, Rider VBA prevents harm to either the ratepayer or the utility from usage that deviates from the average. It also protects ratepayers in the event the utilities generate or choose a forecast that underestimates sales volumes. *Id*. at 9. Absent Rider VBA, such a forecast set rates too high and

> unjustifiably increases revenues and profits to the Utilities. *Id.* With Rider VBA, such a forecast is ineffective at increasing profits, because over collections are refunded to customers.
>
> Another advantage of Rider VBA as pointed out by Dr. Brightwell is that it diminishes the advantage that the utility has from choosing the timing of its next rate case. *Id.* at 5. He maintains that without Rider VBA, a forecast that does not account for sales growth leads to over collections. Under this scenario the Utilities have no incentive to petition for a change in rates because such a petition reduces their profits. However, a forecast over-estimating growth in sales causes the Utilities to under collect, and those Utilities have an incentive to file for an increase in rates. Since most rate cases are filed by the Utilities, this asymmetry is to the Utilities advantage and the ratepayer's.

Peoples Gas 2011 Order at 164.

The AG contends that this rationale no longer applies given the results of the Companies' ECOSS, which show significant demand-related costs. The AG notes that the Companies' arguments supporting Rider VBA and their proposed conditional alternative are flawed in each case because they are based on the incorrect assumption that all of the Companies' costs are fixed, and that customer demand does not drive costs. The Companies' own cost studies show that such assumptions are false. In addition, Mr. Rubin testified on several occasions, and as the cost studies in this case prove, the very high customer charges that result from SFV rates are wholly unrelated to the cost of service and are grossly unfair to low-use customers. AG Ex. 3.0 at 30.

The AG argues that the fundamental flaw in SFV rates – and indeed the Commission's adoption of Rider VBA -- is that they treat demand-related costs as "fixed" even though they are incurred based on the amount of gas customers use. It is grossly unfair to recover demand-related costs on a per customer, rather than a per therm, basis because it causes low-use heating customers (such as those living in small apartments) to subsidize the rates of high-use heating customers (such as those living in large single-family homes). *Id.* at 32-33.

For these reasons, the AG maintains that Rider VBA should be removed from the Companies' tariffs thereby restoring the essential purpose of rate regulation which is to protect consumers from monopolists' market power.

<u>Rider VBA is Unlawful.</u>

a. The Commission's Approval of Rider VBA Contradicts Principles of Utility Ratemaking Established by the

United States Supreme Court and Adopted by Illinois Courts.

The AG argues that the Commission's approval of Rider VBA contradicts seminal U.S. Supreme Court and Illinois Supreme Court case law that articulates what constitutes just and reasonable public utility rates. The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. *Citizens Utility Board v. Illinois Commerce Comm'n,* 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995); citing *Camelot Utilities, Inc. v. Illinois Commerce Comm'n*, 51 Ill.App.3d 5, 10, 365 N.E.2d312 (1977). The U.S. Supreme Court articulated a more specific view of this ratemaking precept in a couple of seminal cases that examined what constitutes a reasonable return within the context of just and reasonable rate setting. All of these cases contradict the view inherent in the Companies' Rider VBA proposal that Peoples Gas and North Shore must be assured receipt of its so-called margin revenue level assumed when rates are established in this case.

The AG notes that in the landmark case *Bluefield Waterworks Improvement Co. v. Public Service Comm'n of West Virginia,* 262 U.S. 279 (1923), the U.S. Supreme Court established that a utility's rates should reflect the opportunity – not a guarantee – to earn a return on its used and useful property when a commission sets rates. In spelling out the factors to be examined by regulators when establishing a utility's rate of return, the high court held that a public utility is entitled to such rates *as will permit it to earn* a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. *Bluefield,* 262 U.S. at 692-693 (emphasis added). The *Bluefield* Court further held that a utility has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. *Id.*

The AG further explains that the Court specified that the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit *and enable it to raise the money necessary for the proper discharge of its public duties*. *Id.* at 693 (emphasis added).

The AG observes that the Supreme Court elaborated on the principles governing rate of return regulation in the case of *Federal Power Commission v. Hope Natural Gas Company,* 320 U.S. 591 (1941). Here, the Supreme Court reaffirmed its holding in *Federal Power Commission v. Natural Gas Pipeline Co.,* 315 U.S.575, 590 (1942) that "regulation does not insure that the business shall produce net revenues." *Hope Natural Gas,* 320 U.S. at 603. The U.S. Supreme Court specifically rejected the notion that a monopoly must be protected from market realities, such as competition or the effects of price on a consumer's demand and use of the service, in *Market St. Ry. Co. v. Railroad Commission,* 324 U.S. 548, 568 (1945). The Supreme Court explained, "Even

monopolies must sell their services in a market where there is competition for the consumer's dollar and the price of a commodity affects its demand and use." *Id. at 568.*

The AG opines that Illinois courts have adopted the *Hope* and *Bluefield* standards and applied them to the regulation of utilities in Illinois: " 'The rate making process under the act, i.e., the fixing of 'just and reasonable' rates[,] involves a balancing of the investor and the consumer interests.' " *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n (1953)*, 414 Ill. 275, 287, 111 N.E.2d 329, quoting *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). Similarly, the Illinois Supreme court earlier established that a just and reasonable rate, therefore, is necessarily a question of sound business judgment rather than one of legal formula, and must often be tentative, since exact results cannot be foretold, and that a just and reasonable rate must be less than the value of the service to consumers. *State Pub. Utils. Comm'n v. Springfield Gas & Electric Co. ,* 291 Ill. 209, 216 218 (1919).

The AG notes that the appellate court elaborated on this pronouncement in *Camelot Utilities, Inc. v. Illinois Commerce Comm'n*, 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977), wherein the Court declared that it is the ratepayers' interest which must come first: "The Commission has the responsibility of balancing the right of the utility's investors to a fair rate of return against the right of the public that it pay no more than the reasonable value of the utility's services. While the rates allowed can never be so low as to be confiscatory, within this outer boundary, if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail." *Camelot Utilities,* 51 Ill.App.3d at 10; *Citizens Utility Board v. Illinois Commerce Comm'n,* 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995).

The AG argues that all of these landmark holdings, as well as Illinois courts' interpretations of the decisions, suggest that the Companies' request for the guaranteed recovery of its "fixed costs" under Rider VBA, has no support in the utility regulatory law that has guided this Commission's establishment of rates. In addition, the AG contends that the Commission's approval of Rider VBA – and thereby adoption of the Companies' mantra that margin revenues must be guaranteed – is tantamount to rejection of the well-established utility ratemaking principles that prescribe what is and is not assured to monopoly utilities under the existing regulatory framework. The AG states that there simply is no basis in state and federal regulatory law to support the Companies' belief that they are entitled to a guaranteed revenue stream that matches a level established in a rate case.

b. The Commission's Approval of Rider VBA Violates the Act's Prohibition Against Single-Issue Ratemaking.

The AG contends that Illinois law is clear that riders are to be used by the Commission only in very specific and exceptional circumstances, as this Court highlighted in its 2010 decision in the case of *Commonwealth Edison v. Illinois Commerce Commission,* 405 Ill.App.3d 389, 411(2d Dist. 2010) After reviewing and laying out in the opinion all pertinent case law addressing riders, this Court established

a clear, two-part test which defined the very limited framework for permissible riders. First, the *ComEd* decision stated that riders are to be used only when they are designed to "recover a particular *cost* if (1) the *cost* is imposed upon the utility by an external circumstance over which the utility has no control and (2) the *cost* does not affect the utility's revenue requirement." *Id.* at 687 (emphasis added). The Court further explained that:

> A rider is appropriate only if the utility cannot influence the expense (*Citizens Utility Board,* 166 Ill.2d at 138 ['a rider mechanism is effective and appropriate for cost recovery when a utility is faced with unexpected, volatile, or fluctuating expenses') and the expense is a pass-through item that does not change *other expenses or increase income* (*Citizens Utility Board,* 166 Ill.2d at 138 (*a valid rider has no 'direct impact on the utility's rate of return*').

Id. at 687 (emphasis added).

The AG argues that Rider VBA by its very nature fails both prongs of that test. First, the isolation and guaranteed recovery of forecasted revenues, which is what Rider VBA does, is not recovery of a pass-through "expense" or "cost" of any kind. There's no particular expense or cost being recovered. Second, the sole purpose of Rider VBA is to guarantee an established revenue stream and change its net income. The AG states that by its very definition, Rider VBA increases income when revenues from residential and small commercial customer classes are down, and decreases income when revenues are up, thereby directly impacting the utility's rate of return. Moreover, the AG asserts that the Commission has repeatedly observed that Rider VBA in fact does affect the Companies' rate of return because in each of the annual reconciliation proceedings that have taken place to date, the Commission orders recorded the differing ROEs, both with and without Rider VBA. *See,* e.g., *See* ICC Docket No. 10-0237,10-0238 (cons.), Order of March 9, 2011 at 3, 6; ICC Docket No. 09-0123 (North Shore), Order of February 10, 2010 at 12; ICC Docket No. 09-0124 (PGL), Order of February 10, 2010 at 12. The AG notes that these Rider VBA reconciliation dockets each specifically cite movement in the ROE as a result of the Rider VBA adjustments.

c. Rider VBA Violates the Act's Prohibition Against Retroactive Ratemaking.

The AG argues that Rider VBA should also be terminated because it violates the Act's prohibition against retroactive ratemaking by permitting annual rate adjustments after rates are established in this case. Rider VBA conflicts with traditional prospective ratemaking and the rule against retroactive ratemaking because it illegally locks in an artificial level of revenues per customer – a benchmark never before recognized in utility ratemaking – through a formula that triggers annual rate adjustments for residential and small business customers after rates have been established in a rate case order. These adjustments are made to guarantee what the Commission now believes is a utility entitlement, the artificial benchmark of a set revenue level per customer class, rather than the recovery of certain expenses that qualify for rider treatment, such as purchased gas, environmental remediation expenses and legally mandated fees.

The AG also argues that Rider VBA absolutely suggests that the rates (charged under the order establishing the revenue requirement) are in some way excessive or insufficient. The Order unequivocally provides that if revenues from residential and small business customers do not meet the benchmark revenue level established for each class each year, then they are either excessive, thereby requiring a Rider VBA reduction, or insufficient, thereby requiring a Rider VBA surcharge. The shortfall or excess tabulated in the Rider VBA true-up is collected over a nine-month period beginning each April.

The AG opines that this seesawing of monthly surcharges (or credits) triggered by Rider VBA is the kind of retroactive adjustment of rates that Illinois courts held were illegal. Section 9-201 of the Act ensures that rates for utility service are set prospectively. 220 ILCS 5/ 9-201. The Illinois Supreme Court has held repeatedly that the Act does not permit retroactive ratemaking; that is once the Commission establishes rates, the Act does not permit refunds if the established rates are too high, or surcharges if the rates are too low. *BPI I,* 136 Ill.2d at 209; *Citizens Utilities Co. v. Illinois Commerce Comm'n,* 124 Ill. 2d 195, 207; 529 N.E.2d 510 (1988). The AG asserts that Rider VBA violates the prohibition against retroactive ratemaking by permitting annual rate adjustments after rates are established in this case that are not contemplated by the Act.

The AG concludes that it is clear the Commission lacks the authority to approve Rider VBA given the absence of specific statutory authority authorizing the retroactive adjustment of customer rates on an annual basis to ensure a benchmark revenue level for two customer classes.

d. Rider VBA Violates the Commission's Test Year Rules.

The AG argues that Rider VBA also violates the Commission's test year rules. The AG explains that the process used to evaluate and measure the cost of service and resulting revenue requirement is the rate case, in which a balanced review of jurisdictional expenses, rate base investment, the cost of capital and revenues at present rates can be undertaken at a common point in time referred to as a test period or test year. *See BPI II*, 146 Ill.2d at 175, 238. In order to accurately determine the utility's revenue requirement, the Commission established filing requirements under which a utility must present its rate data in accordance with a proposed one-year test rule. *See* 83 Ill.Admin.Code Part 285. Section 287.20 of the Commission's rules provides that a utility may, at its option, propose either an historical or a future test year. 83 Ill.Admin.Code Part 287.20. The purpose of the test-year rule is to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one year with high expense data from a different year. *BPI I,* 136 Ill.2d at 219.

The AG states that adjusting customer rates while ignoring all other elements in the ratemaking formula to reflect a single component of the revenue requirement established in a rate case – a designated revenue benchmark level for Rates 1 and 2 --

constitutes a violation of the test year rules. The calculation of Peoples Gas' and North Shore's revenues for purposes of setting rates is subject to test-year principles. Rider VBA violates the Commission's and Illinois law's test-year principles by selecting only one component of the revenue requirement, in this case a slice of overall revenues (margin revenues per customer in the Rate 1 and 2 classes), tracking changes in that revenue requirement component and then assessing rate adjustments to recognize this change. The AG contends that such an approach distorts test year matching by continuously revising utility prices for changes in future usage per customer, even though other elements of the test year revenue requirement calculation are not being systematically updated.

e. Illinois Law is Clear that "Lost Revenues" Cannot be Recovered Through A Rider.

The AG observes that the Illinois Appellate Court in the *Finkl & Sons v. Illinois Commerce Comm'n,* 250 Ill.App.3d 317 (1st Dist. 1993) ("*Finkl*"), specifically reversed the Commission's approval of a rider that required ratepayers to reimburse a utility for revenues lost due to energy efficiency and conservation measures. The AG states that in *Finkl*, the rider at issue, like Rider VBA, also would have authorized ComEd to charge ratepayers for lost revenues associated with demand-side management activities, similar to the Companies' request in this docket to adjust rates each month when margin revenues fall below a revenue per customer baseline established in this Order. The *Finkl* Court noted that rider recovery of lost revenues associated with the DSM programs "fails to take into consideration Edison's aggregate costs and revenues, which is also the vice inherent in this revenue recapture…" *Finkl,* 250 Ill.App.3d at 328. The Court flatly rejected the notion of making a utility whole for lost revenues associated with conservation or DSM programs:

> "Requiring ratepayers to bear the expense of services they avoid due to conservation or DSM programs is not only incredible, but runs afoul of basic ratemaking principles. The Act requires that rates be set which 'accurately reflect the long-term cost of such services and which are equitable to all citizens.' (Ill.Rev.Stat.1989, ch. 111 2/3, par. 1-102 (now 220 ILCS 5/102 (West 1992))(section 1-102).) Both in *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n* (1973), 55 Ill.2d 461, 483, 303 N.E.2d 364, and in C*andlewick Lake Utilities Co. v. Illinois Commerce Comm'n* (1983), 122 Ill.App.3d 219, 227, 460 N.E.2d 1190, the courts have asserted that ratepayers are not to pay certain costs unless they directly benefit from them. The lost revenue charge here does not reflect the cost of providing electric service, does not reflect a cost that benefits ratepayers and, further, adds to Edison's revenues without regard to whether Edison's demand or revenues increased because of factors

> unrelated to DSM programs. This is yet another basis for reversal.

Id. at 329.

The AG posits that the notion of reimbursing Peoples Gas and North Shore for declining revenues associated with, among other phenomena, energy efficiency and conservation, is at the heart of the Companies' decoupling proposal. The AG states that approval of Rider VBA violates the Act's requirement that rates be set which "accurately reflect the long-term cost of such services and which are equitable to all citizens." 220 ILCS 5/102. Ratepayers are not to pay certain costs unless they directly benefit from them. *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n* (1973), 55 Ill.2d 461, 483, 303 N.E.2d 364, and in *Candlewick Lake Utilities Co. v. Illinois Commerce Comm'n* (1983), 122 Ill.App.3d 219, 227, 460 N.E.2d 1190. The AG argues the Commission had no authority to require ratepayers to pay for gas delivery service they are not using since they derive no benefit from service they do not use. In addition, the AG further argues that given the clear direction provided by the *Finkl* Court in its specific rejection of ratepayers compensating a utility for lost revenues arising from energy efficiency and other measures, as well as the Act's requirement that ratepayers shall only pay for utility costs that directly benefit them, the Commission's decision to approve Rider VBA should be terminated.

For all of the reasons discussed above, the AG contends that the Commission should terminate Rider VBA.

CUB-City

CUB-City note that this is the third proceeding in which the Commission has considered Rider VBA. CUB-City explain this rider was initially approved in PGL/NS's 2007 rate case on a pilot basis. February 8, 2008 Order, Docket No. 07-0242 at 151-153. CUB and the AG challenged the legality and propriety of Rider VBA in that proceeding and – after it was approved – at the appellate court. Gen. No. 2-11-0380. However, before the Second District Appellate Court decided that appeal on the merits, the Companies petitioned for – and the Commission approved – Rider VBA on a permanent basis in the utilities' 2011 rate case. January 10, 2012 Order, Docket No. 11-0280(cons.) at 163-164. CUB and the AG appealed that decision as well. Gen. No. 2-12-0243, consolidated with case number 2-12-0349. CUB-City further explain that since the permanent Rider VBA was identical to the pilot rider, the parties agreed to seek dismissal of the 2007 appeal. The appeal of permanent Rider VBA is now pending at the Second Judicial District. CUB and the AG continue to challenge the legality and evidentiary basis for Rider VBA in this proceeding also.

The Record in This Proceeding Undermines the Prior Justification for Rider VBA.

CUB-City explain that in the last PGL/NS rate proceeding, the Commission approved the permanent Rider VBA as an alternative to a SFV/fixed charges rate design. January 10, 2012 Order, Docket No. 11-0280(cons.) at 163-164. The presumption underlying the theory of decoupling – and Rider VBA – is that all the utilities' costs are fixed; that is, the entire revenue requirement represents fixed costs. CUB-City aver that the Companies' own cost studies in this proceeding demonstrate, however, that customer demand– and the corresponding costs to serve that demand – vary greatly within the residential class. Thus, CUB-City state that recovering demand-related costs on a per customer, rather than volumetric, basis inevitably causes low-use heating customers to subsidize the rates of high-use heating customers. AG Ex. 3.0R at 31. For this reason, CUB-City argue that Rider VBA is grossly unfair and results in significant intra-class subsidies, when a customer class includes large users, small users, seasonal peaking customers, and non-peaking customers. *Id*.

CUB-City agree with AG witness Rubin's opinion that the fundamental problem with decoupling as reflected in Rider VBA is the assumption that the utility is entitled to recover a certain level of revenues from each customer class, or, as it defines them, its fixed costs. AG Ex. 3.0R at 26. CUB-City aver that traditional rate-of-return regulation provides utilities with the opportunity to earn a particular return based on a test-year estimate of the amount of services the utility will sell (using forecast methodology) – not a guarantee. *Id*. CUB-City note that no utility customer is required to use a certain amount of the utility's service, and a customer is free to use none at all if it so desires. *Id.* This opportunity to earn a particular return is provided in exchange for providing the monopoly firm the opportunity to operate and serve a captive customer base. CUB-City aver that while the firm is exposed to the risk that its customers will not use as much of the service as forecasted, and that its revenues may decline as a result, it also enjoys the reward if forecasted usage is greater than predicted. On the other hand, customers assume the risk that this utility provide safe, reliable and affordable utility service – a risk not borne in a competitive market with multiple service providers.

CUB-City contend that Rider VBA turns this regulatory compact on its head by virtually guaranteeing the utilities an established revenue stream, regardless of weather conditions, the community's financial circumstances, global energy concerns, appliance and equipment offerings in the marketplace, or the price and quality of the utility's service. AG Ex. 3.0R at 28. CUB-City explain that this high degree of revenue assurance brings with it perverse incentives, where actions or inactions by the utility that would otherwise be prudent management would be foregone because of the failure of these actions to influence the utility's revenue streams.

Rider VBA is unlawful.

CUB-City note that the debate about whether Rider VBA is lawful must begin with a review of the fundamental regulatory construct underlying traditional rate-of-return

regulation. In *Citizens Utilities Co. v. Ill. Comm. Comm'n*, 124 Ill.2d 195 (1988) ("*Citizens Utility*"), the Illinois Supreme Court described the process by which the Commission sets a utility's rates. The Supreme Court explained that:

> In establishing the rates that a public utility is to charge its customers, the Commission bases the determination on the company's operating costs, rate base, and allowed rate of return. A public utility is entitled to recover in its rates certain operating costs. A public utility is also entitled to earn a return on its rate base, or the amount of its invested capital; the return is the product of the allowed rate of return and rate base. The sum of those amounts operating costs and return on rate base is known as the company's revenue requirement. The components of the ratemaking determination may be expressed in "the classic ratemaking formula R (revenue requirement) = C (operating costs) + Ir (invested capital or rate base times rate of return on capital)."

Citizens Utility, 124 Ill. 2d at 200-01. CUB-City assert that the court in *Finkl*, explained further that, in examining test year costs, "the Commission is required to consider all aspects of the utility's operations during a year selected by the utility as a test year. The test year so selected is intended to be representative of both the utility's anticipated rate-base expenses and its expected revenues, including overall costs and rate of return in the same year." *Finkl*, 250 Ill. App. 3d at 325. CUB-City note that the process described in the *Citizens Utility* and *Finkl* cases has been in place for decades and is the foundation of rate-of-return regulation. Recovery of costs outside of the traditional rate-setting process is not permitted except in special circumstances. CUB-City aver that except in those special circumstances, which are described below, allowing a utility to recover a particular cost in isolation without considering the entire and panoply of costs and expenses violates the rule against single-issue ratemaking.

CUB-City note that in *BPI II*, the Illinois Supreme Court described the rule against single-issue ratemaking as follows:

> The rule against single-issue ratemaking recognizes that the revenue formula is designed to determine the revenue requirement based on the *aggregate* costs and demand of the utility. Therefore, it would be improper to consider changes to components of the revenue requirement in isolation. Often times a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. For example, an increase in depreciation expense attributable to a new plant *may* be offset by a decrease in the cost of labor due to increased productivity, or by increased demand for electricity. (Demand

> for electricity affects the revenue requirement indirectly. The yearly revenue requirement is divided by the expected demand for electricity to arrive at a per kilowatt hour rate. If actual demand is more than the estimated demand used in the formula, the utility's revenues increase.) In such a case, the revenue requirement would be overstated if rates were increased based solely on the higher depreciation expense without first considering changes to other elements of the revenue formula. Conversely the revenue requirement would be understated if rates were reduced based on the higher demand data without considering the effects of higher expenses.

BPI II, 146 Ill. 2d at 244-45.

CUB-City point out that the exception permitting recovery of costs outside of the traditional rate-setting process is recovery through riders. Riders allow a utility to collect revenues associated with a particular cost as it is incurred, without waiting until it files a general rate case to recover such expenses. CUB-City state that in other words, rider cost recovery allows utilities to collect a cost in isolation without "consider[ing] *all* aspects of the utility's operations during a year selected by the utility as a test year." *Finkl*, 250 Ill. App. 3d at 325 (emphasis added). However, rider recovery is permitted only under certain well-defined and very limited circumstances. CUB-City observe that in *Finkl*, the appellate court stated that riders are permissible where the costs in question are "*unexpected, volatile* or *fluctuating*" and beyond the control of the utility. *Id*. at 327 (emphasis added). The *Finkl* court identified fuel costs as an example of an expense that meet the enumerated criteria: fuel costs can be volatile, can fluctuate and can be beyond a utility's control. *Id*.

CUB-City further explain that the Illinois Supreme Court ruled in accordance with the *Finkl* court's holding in *Citizens Utility Board v. Ill. Comm. Comm'n.*, 166 Ill. 2d 111 (1995) ("*CUB*"). In the *CUB* case, the Supreme Court reviewed the Commission's generic order allowing utilities to recover through a rider clean-up costs incurred in remediating former manufactured gas plant ("MGP") sites. *Id.* at 116. The Supreme Court held there was evidence showing that the costs to remediate MGP sites were "uncertain and variable" and, thus, appropriate for rider recovery. *Id.* at 138-39. CUB-City note that in *Finkl*, the appellate court reviewed a Commission order approving ComEd's proposed Rider 22, which allowed ComEd to recover the costs of demand side management programs (*i.e.*, energy efficiency programs) through a rider. *Finkl*, 250 Ill. App. 3d at 322. The appellate court reversed the Commission's order stating, in relevant part, that the types of costs that could be recovered through Rider 22 "reveal no greater potential for unexpected, volatile or fluctuating expenses which Edison cannot control, than costs incurred in estimating base ratemaking." *Id*. at 327. The court added that any uncertainty in determining demand side management costs could be addressed through the traditional base rate setting process. *Id*. CUB-City conclude

that based on the criteria established in Illinois Supreme Court and appellate court cases, margin revenues are not appropriately recovered through a rider.

Accordingly, CUB-City recommend that the Commission reject Rider VBA as legally infirm and lacking a supportable evidentiary basis.

Commission Analysis and Conclusions

The Commission has considered the legality and propriety of Rider VBA in two previous proceedings. The Commission has explained its reasoning in great detail for supporting Rider VBA as a four-year pilot program in the Utilities' 2007 rate case and as a permanent rider in the Utilities' 2011 rate case. As stated previously in this Order, the Commission continues to believe that Rider VBA is a sound rate design policy that should remain in place permanently as approved by the Commission in the Utilities' 2011 rate case and as affirmed by the Illinois Appellate Court in its recent decision issued on March 29, 2013. The Commission notes that the Court held that the Commission's adoption of Rider VBA on a permanent basis in the Utilities' 2011 rate case did not violate either the rule against retroactive ratemaking or the rule against single-issue ratemaking and that the findings of the Commission were supported by substantial evidence. Accordingly, the Commission rejects the AG's and CUB-City's proposal to terminate Rider VBA.

Additionally, the Commission notes that it makes no changes to Rider VBA and its applicability. The percentage of fixed costs recovered under the rider will remain at 100%. The Commission does not believe there is any basis for changing this percentage at this time.

X. Transportation Issues

A. Uncontested Issues

1. Purchase of Receivables (Withdrawn)

IGS Energy witness Mr. Vincent Parisi in his direct testimony (IGS Energy Ex. 1.0) made a proposal that Peoples Gas and North Shore be ordered by the Commission to begin a Purchase of Receivable ("POR") program for Choices For You ("CFY") suppliers. Staff Ex 18.0 at 2. Staff witness David Rearden responded to that IGS Energy proposal among others made by Mr. Parisi in his rebuttal testimony. Mr. Rearden recommended that the Commission <u>not</u> order Peoples Gas and North Shore to initiate such a POR program. *Id*. at 3. IGS Energy withdrew its POR program proposal. IGS Energy Ex. 2.0 at 6. The Commission finds that since IGS Energy has withdrawn its POR program proposal for CFY suppliers the issue is moot.

2. Commission Authority to Order Investigation on Provider of Last Resort

The Utilities took no position on the Commission's authority to conduct an investigation on provider of last resort.

IGS Energy indicates that it is uncontested that the Commission possesses the legal authority to investigate whether the Companies should continue to serve as the provider of last resort. IGS Energy points out that the Commission possesses broad investigatory authority under the Act and regularly conducts investigative proceedings on a wide variety of topics ranging from substantial policy questions to particular administrative practices. *See* IGS Energy Initial Brief at 9-10, 28. Neither the Companies nor Staff dispute this point in their Initial Briefs or in any testimony or other submission. As IGS Energy pointed out in its Initial Brief, the Companies and Staff accept as a foregone conclusion that the Commission has the *ability* to order an investigation into whether the Companies should continue to act as the provider of last resort. *See Id.* at 10.

The Commission clearly possesses broad investigatory authority under the Act and could initiate an investigation of whether the Companies should continue to act as the provider of last resort.

B. Contested Issues

1. Cost Allocation Between Sales Customers and Small Volume Transportation Customers

Utilities

Utilities witness Ms. Grace stated that the Utilities significantly revised their transportation programs in 2011 (small volume program) and 2012 (large volume program), including implementing new administrative charges, approved in the 2011 rate cases, for both programs in January 2012. Therefore, Ms. Grace explained that the Utilities proposed no changes in this proceeding. NS Ex. 12.0 Rev. at 23; PGL Ex. 12.0 Rev. at 23-24. In the 2011 rate cases, the Commission concluded that sales customers do not cause the costs that the Utilities recover from Rider AGG, Aggregation Service, suppliers. *Peoples Gas 2011* Order at 234. No evidence of changed circumstances exists.

IGS Energy

IGS Energy observes that in order to encourage a vibrant and growing competitive retail market, the manner in which the Companies allocate administrative costs between Sales customers and Choices For You customers must be changed. IGS Energy notes that the Companies' current allocation of administrative costs is harmful to consumers and the competitive market because: (1) Choices For You customers are being charged for costs they do not cause; and (2) certain costs have been identified by the Companies as being attributed solely to Choices For You customers, even through the Companies have not properly reviewed and allocated all other base rate costs to the proper cost causers. *See Id*.

IGS Energy explains that the Companies improperly have pulled out the one set of administrative costs associated with Choices For You, and recovered those costs solely from Choices For You customers, while continuing to charge the Choices For You customers for administrative costs incurred to provide service to the Companies' Sales customers. IGS Energy submits that since the Companies have freely admitted that they do not track their base rate costs, the best solution would be for the Commission to direct the Companies to simply spread all the administrative costs among all customers who have the option to participate in the Choices For You program, mitigating the need to further examine such base rate costs.

IGS Energy observes that the Companies do not attempt to substantively defend the manner in which they track and analyze costs. The Companies state:

> In the 2011 rate cases, the Commission concluded that sales customers do not cause the costs that the Utilities recover from Rider AGG, Aggregation Service, suppliers. Peoples Gas 2011 at 234. No evidence of changed circumstances exists. The Commission should reject IGS Energy's arguments that the Utilities do not properly allocate costs between sales customers and alternative gas suppliers.

See the Companies' Initial Brief at 163-164. IGS Energy notes that that is the Companies' argument in its entirety. IGS Energy expresses surprise at the Companies' failure to engage, given the level of evidence developed by IGS Energy on cost allocation issues in this proceeding.

IGS Energy states that the Companies' suggestion that the 2011 rate case decision is conclusively dispositive of any administrative charges issue raised in this proceeding is unconvincing. IGS Energy observes that the Companies themselves regularly ask the Commission to revisit issues that are important to them, and it is a basic rule of Commission procedure that similar issues may be raised in succeeding proceedings. *See, e.g., Commonwealth Edison Co. v. Ill. Commerce Comm'n,* 405 Ill. App. 3d 389, 407-408 (2nd Dist. 2010) (holding that a "record containing new evidence or argument that implicates past decisions compels reconsideration on the new record and may require a different result."). IGS Energy explains that this approach makes sense, for the simple reason that time and experience sometimes show that a decision made at one moment may not apply to facts as they exist at a later moment. IGS Energy submits that that is precisely the case here: while Choices For You participation rates continue to fall, the Companies refuse to engage in any substantive discussion of the problem, propose no changes to fix the program and reject common-sense solutions.

Although the Companies take the position that Choices For You customers should not be "penalized" for taking supply from an alternative suppliers (*see* Tr. at 474), IGS Energy observes that the Companies have presented no analytical evidence in this proceeding to demonstrate that they have appropriately allocated administrative costs and at the same time have admitted they only identify costs which they attribute to

Choices For You customers and recovered those costs solely from Choices For You customers. *See* Tr. at 853. IGS Energy points to the evidence of the Companies' admission that they do not even attempt to identify similar administrative costs incurred to provide service to the Companies' sales customers. *See Id.* at 853-854 ("Q. But there's not a similar breakout just for only traditional utility sales customers' administrative costs, correct? A. Right".). IGS Energy notes that, in effect, the Companies have confirmed that they intentionally continue to implement a "dumb accounting" system that is systematically designed to stifle competition.

IGS Energy points out that the Companies *assert* that they believe in the ratemaking principle that costs should be recovered from the cost-causer. *See* Tr. at 462; Tr. at 828. However, IGS Energy points to the evidence demonstrating that the Companies do not accurately track or analyze the administrative costs that can clearly be attributed to the Sales class of customers -- and then they proceed to spread such costs equally amongst the Companies' Sales customers and the Choices For You customers. *See Id*. at 13-14, *citing* IGS Energy Ex. 2.0 at 345-349; *see also* IGS Energy Cross Exs. 15-17; IGS Energy Ex. 2.3. As a result, the Companies are collecting "untracked" costs -- such as the costs associated with hedging their supply of natural gas and the collection of bad debt -- from Choices For You customers who do not cause the costs.

IGS Energy says that the Companies' failure to advance pro-competitive policies should come as no surprise. According to IGS Energy, the Companies repeatedly have turned a blind eye to the failures of their customer choice program. IGS Energy notes that as recently as February 21, 2013, in providing comments to the Commission's Office of Retail Market Development relating to the Section 19-130 Annual Report regarding the Development of Competitive Retail Natural Gas Markets, the Companies reiterated their truculence to embrace productive change with regard to choice programs, stating:

> The Companies *have not performed analysis* to identify barriers to the development of competitive retail natural gas markets in Illinois, *but believe the competitive market exists and is operating well* with approximately 64,000 Peoples Gas and 14,000 North Shore customers enrolled in transportation programs. *The Companies have been responsive to industry changes,* and have made numerous modifications over time to both small and large volume transportation programs that are beneficial to end-use customers and Suppliers.

The Companies February 21, 2013 Initial Comments regarding the 19-130 Annual Report (emphasis added) (attached to IGS Energy's Reply Brief as Exhibit A).

Accordingly to IGS Energy, this statement encapsulates the Companies' antagonistic attitude toward retail choice. First, the Companies state that they "have not performed analysis to identify barriers to development of retail natural gas markets in Illinois." IGS Energy asserts that this is consistent with the evidence in this proceeding.

See e.g., Tr. at 912, 936. IGS Energy also observes that given the Companies lack of introspection, their assertion that the competitive market is "operating well" in their service territories is a complete *non sequitur* and lacks credibility.

IGS Energy notes that after the Companies admitted that they have performed zero analysis regarding the barriers to revitalizing their choice program, the Companies simply throw out enrollment numbers to suggest that because some customers are enrolled today, their program is fine. IGS Energy explains that the Companies provided those enrollment numbers without any context -- and that even a cursory review of the enrollment statistics show that:

- The number of customers enrolled in Choices For You has dropped dramatically in the last three years, by nearly a third (*see* IGS Energy Initial Brief at 12, *citing* IGS Energy Cross Exs. 25, 26);
- The percentage of customers enrolled in Choices For You is about half the percentage enrolled in the Nicor Gas retail choice program (*see Id*. at 12, *citing* IGS Energy Cross Exs. 19, 20, 21, 22, 23; IGS Energy Ex. 2.1); and
- The number of suppliers participating in the Nicor Gas program dwarfs the number of suppliers participating in the Companies' Choices For You program (*See Id.*).

IGS Energy characterizes the Companies' further suggestion that they "have been responsive to industry changes" as plainly incorrect, since the Companies has been completely unresponsive to industry changes. For example, IGS Energy notes that the Companies continue in their absolute refusal to recover choice-related administrative costs from all eligible customers -- a practice that has been in place in the Nicor Program since the conclusion of Nicor's *2008* rate case (ICC Docket No. 08-0363), a proceeding in which Nicor voluntarily agreed to modify its cost-recovery approach and Staff endorsed that approach. *See* IGS Energy Cross Ex. 7 (2008 Nicor Rate Case, ICC Docket No. 08-0363, Rebuttal Testimony of David Sackett at 46).

IGS Energy recalls that in the Companies' 2009 Rate Case (ICC Docket No. 09-0166/0167), alternative retail gas suppliers requested that the Companies modify their cost recovery mechanism to mirror that of Nicor, and the Companies refused to even examine the terms of the Nicor program. *See* September 29, 2009 Initial Brief of the Retail Gas Suppliers at 26, ICC Docket No. 09-0166/0167. IGS Energy notes that the Commission found the Companies' actions (or inaction) to be inappropriate, and went so far -- in light of the "compelling evidence" about the problems with the Companies' Choices For You program -- as to direct the Companies to conduct workshops and to specifically use the Nicor model as the starting point for workshop discussions on revisions to the Choices For You program. *See* January 21, 2010 Final Order at 253, 260, ICC Docket No. 09-0166/0167. Yet, as IGS Energy reports, the Companies refused to implement the appropriate changes in the allocation for administrative fees, and they persisted in their "dumb accounting" system upon which they continue to rely to resist change. *See* IGS Energy Ex. 1.0 at 32-33. According to IGS Energy, any

suggestion by the Companies that they have been "responsive to industry changes" contradicts the facts and lacks credibility, according to IGS Energy.

IGS Energy notes that in its Initial Brief, Staff agrees with IGS Energy that the Companies have failed to track the costs included in the Companies' general administrative charge. *See* Staff Initial Brief at 116. Staff acknowledges that administrative costs associated with the supply of gas and uncollectibles are not accurately tracked by the Companies, noting that Dr. Rearden specifically argued "that those costs are not tracked." *Id.* Staff then recommends no changes relating to these costs because it was "less clear" to Dr. Rearden whether sales customers are the "sole cost causers." *Id.* IGS Energy respectfully characterizes Staff's argument is confusing, at best. Staff agrees with the basic fact that the Companies do not track and examine their base rate administrative costs. According to IGS Energy, this is a critical piece of information and suggests at a minimum that this issue requires some investigation or other attention. Yet Staff proposes no action at all be taken on the basis of a equivocal observation by Dr. Rearden that it is "less clear" whether sales customers are the "sole cost causers."

IGS Energy characterizes that approach as problematic for at least two reasons. First, IGS Energy is not suggesting that there are *no* administrative costs that are caused by choice customers -- some are. On this point, Dr. Rearden's equivocal statements about it being "less clear" who causes the costs is not dispositive. IGS Energy is only suggesting that the costs be allocated among all of the customers -- both choice and non-choice -- in a manner exactly like other programs where the program benefits all customers and there has not been a full examination of all rates is not undertaken to ensure that all costs are borne only by the costs causers.

Second, Dr. Rearden's observation begs the question -- who *is* causing the costs about which he is concerned? In light of that question, at the very least, IGS Energy believes that Staff should have recommended that the Commission require the Companies to start tracking clear categories of costs that are caused by Sales versus Choices For You customers. IGS Energy notes that this would be consistent with Dr. Rearden's clear statement at the Evidentiary Hearing that the Commission possesses the authority to require utilities such as the Companies to track costs and modify billing systems as necessary to capture accurate cost allocation. *See* Tr. at 278. IGS Energy emphasizes that if costs are properly tracked, then a proper examination could occur to ensure that costs are paid for by the appropriate parties in all categories. Unless and until the Companies track these costs more comprehensively, such time it is simply inequitable to identify one bucket of costs, without any substantiation, and direct those costs to Choices For You customers.

In short, IGS Energy concludes that nothing in the cursory statements by the Companies or Staff about administrative costs rebuts in any substantive manner the evidence in this proceeding which demonstrates that the Choices For You program is broken and that the recovery of administrative fees associated with that program needs to be revised.

Staff

Staff witness Dr. Rearden addressed the recommendation by IGS Energy witness Vincent Parisi that Peoples Gas and North Shore be directed by the Commission to revise their administrative charges to better reflect cost causation principles. IGS Energy Ex. 1.0 at 44. Mr. Parisi made two recommendations. One, IGS Energy was recommending that North Shore and Peoples Gas should stop charging CFY customers for costs that they allegedly do not cause, or in the alternative that CFY customers be given a credit for those costs. Two that CFY administrative costs are recovered from both sales and transportation customers and not just CFY customers. *Id*. at 5-6. Dr. Rearden testified that:

> [u]tility rate making is a complicated enterprise that involves allocating costs between many different competing groups. There are many examples of costs that the utility incurs that are paid for by all customers but might benefit one group more than another at a point in time. For example, construction in one part of town may have no effect on customers' services in another part of town. There is typically not enough data to disaggregate costs to specific types of customers.

Id. at 4. Dr. Rearden further noted that it is not always clear who is the cost causer. But in the case of the costs of CFY programs, those costs are tracked and are clearly caused by the transportation customers. With respect to the administrative services that Mr. Parisi alleges are mis-allocated to transportation customers, Dr. Rearden argued that those are costs that are not tracked like the CFY costs and it was less clear to him that sales customers are the sole cost causers. Given the above, Staff recommends that the Commission not make any changes as to how rates are calculated for these costs. *Id*. at 8.

Commission Analysis and Conclusions

IGS Energy raises no new issues and presents no new evidence that was not addressed thoroughly in the Utilities' 2011 rate cases. As Staff explained, cost causation is not a simple issue. Moreover, the Commission agrees with the Staff that participation levels in a program are not necessarily indicative of whether the program is well-designed. The Commission finds that it was reasonable for the Utilities to make no changes to the administrative charges that the Commission so recently reviewed and approved. The Commission makes no other findings about the design of or other aspects concerning the Utilities' programs.

2. Recovery of Supply-related Costs from Small Volume Transportation Program (Choices for You^{SM} or "CFY") Customers

Utilities

Utilities witness Ms. Grace stated that the Utilities' gas supply personnel provide support for securing and managing the services and assets that underlie storage and balancing services. Although CFY customers buy their gas from alternative suppliers, the Utilities continue to provide delivery service and storage and balancing services so that the transportation programs can exist. Suppliers have no obligation to deliver the precise amount of gas their customers use every day. Moreover, under certain conditions, CFY suppliers buy company-supplied gas through cash-outs. NS-PGL Ex. 48.0 Rev. at 17; *also see* Section X.B.1, *supra.* Thus, CFY customers (and suppliers) benefit from the Utilities' gas supply functions, and it is appropriate that all customers' base rates include these costs.

IGS Energy

IGS Energy explains that Choices For You customers -- who obtain their natural gas supply from alternative gas suppliers -- improperly are being charged supply-related administrative costs that are caused by the Companies' sales customers. In IGS Energy's view, this flaw in the program skews the economics of the program, and acts as an artificial barrier to customers entering the competitive market. IGS Energy observes that neither the Companies nor Staff dispute the fact that Choices For You customers are being charged for supply-related administrative costs; rather, they attempt to justify the Companies' actions.

IGS Energy asserts that the Companies' accounting system is designed in a manner that results in the Choices For You customers being allocated Sales customers' supply-related administrative costs. *See* Tr. at 847-848. By their own admission, the Companies have not designed their accounting systems to accurately track categories of costs that are caused by their Sales customers only and do not separately track costs caused on different proportions by Choice and Sales customers. *See* Tr. at 853-854. Thus, IGS Energy notes that although, on the one hand, the Companies and Staff assert that costs should be allocated to the cost causers (*see, e.g.,* Tr. at 468; Tr. at 834, 836-837; Tr. at 282, 290, 299, 301-302), on the other hand, the only fees specifically broken out from base rates are allocated to Choices For You customers, without an examination of other base rate charges that clearly are attributable only to Sales customers. *See* Tr. at 853-854. IGS Energy notes that this means that the supply-related administrative costs are collected from all customers, including Choices For You customers who do not cause those costs.

IGS Energy notes the Companies make a new assertion in their briefs that supply-related costs are properly allocated to Choices For You customers because the Choices For You Customers *benefit* from these functions. *See* Companies' Initial Brief at 164. IGS Energy points out that as an initial matter, the Companies' embrace of a "benefit" test at this stage is odd since the Companies have attempted to distance themselves from the idea that customers who benefit from the Choices For You program should pay for it. Tr. at 836. ("Q. You believe that cost causation is a black-and-white question? A. I think that it's easier to determine cost causation than

benefits."); *see also* IGS Energy Cross Ex. 19 ("[The Companies'] [c]osts are allocated based on cost causation principles rather than a speculation of customer benefits".). IGS Energy asserts that the Companies' willingness to switch ratemaking principles based simply upon what serves their immediate needs in a particular context seriously undermines the Companies' credibility.

IGS Energy also points out that the Companies' new suggestion seems to be that since there may be *some* scenario under which *some* Choices For You customers' suppliers *might* benefit from a discrete portion of the Companies' supply program, it is appropriate to fully charge the Choices For You customers for all supply-related administrative costs. IGS Energy stresses that the Companies' position is contrary to cost-causation principles; it is also the exact opposite way in which the Companies treat Choices For You customers; and it ignores the evidentiary record in this proceeding.

IGS Energy notes that cost causation principles dictate that the costs should be borne by the cost-causer -- this is a non-controversial proposition endorsed by the Companies and Staff. *See, e.g.,* Tr. at 468; Tr. at 834, 836-837; Tr. at 282, 290, 299, 301-302.

However, IGS Energy emphasizes IGS Energy witness Mr. Parisi's testimony, where he explained:

> The principle of cost causation is only equitable if and when all costs are appropriately allocated to those who cause such costs; not when only certain costs are allocated and others are spread among all customers irrespective of causation. What the Utilities have done is pulled out the one set of administrative costs associated with Choices For You and recovered those costs solely from Choices For You customers while continuing to charge the Choices For You customers for administrative costs incurred to provide service to the Utilities' sales customers. This is inappropriate, and should be remedied immediately.

IGS Energy Ex. 2.0 at 7.

IGS Energy observes that additional irony that in the context of allocating Choices For You administrative costs, the Companies *have* sought to identify some specific administrative costs and assign those costs. The way in which they have sought to do so is unlike any other Illinois utility and unlike any other program of the Companies' -- but the idea of identifying administrative costs and appropriately allocating them is non-controversial.

Finally, IGS Energy points out that the Companies position simply ignores the evidentiary record in this proceeding. IGS Energy has identified two discrete costs that the Companies incur which are *exclusively* for the benefit of Sales customers: (1) costs associated with Sales customers' bad debt collection; and (2) costs associated with gas hedging. *See* IGS Energy Ex. 2.0 at 15-17.

IGS Energy explained that Choices For You customers have an extremely low uncollectible rate -- this is a result of the Companies not having a POR program and instead having an allocation of payment methodology that favors payment of utility charges over supplier charges. *See* IGS Energy Ex. 2.0 at 15-16. Accordingly, if Choices For You customers cause any portion of the Companies' costs related to uncollectable expenses, that portion is *de minimis*. IGS Energy notes that the Companies did not contest this point during the Evidentiary Hearings.

According to IGS Energy, because Choices For You customers cause virtually no uncollectable expenses of any kind, they do not cause costs incurred in support of attempted collection of uncollectable expenses beyond normal billing expenses. Those costs include the capital, direct O&M, and indirect O&M costs associated with any collections beyond sending the initial bill. IGS Energy maintains that, as a result, the Companies improperly charge Choices For You customers for all of these costs.

IGS Energy again stresses that neither the Companies nor Staff presented any specific evidence related to the Companies' improper recovery of bad debt costs from Choices For You customers; and in their briefs neither the Companies nor Staff rebut IGS Energy's evidence. The Companies simply make the high-level assertion that Choices For You customers benefit from supply-related costs and, for that reason, it is appropriate to include such costs in their base rates. *See* Companies Initial Brief at 164. Staff relies upon its general argument that these costs are not clearly tracked by the Companies and due to that failure, it is not clear that the sales customers are the sole cost causers. *See* Staff Initial Brief at 116.

Similarly, IGS Energy asserts that hedging costs represent a prime example of costs caused by and benefiting only Sales customers. IGS Energy observes that the sole purpose of the Companies' hedging program is to minimize the volatility in the Sales customers' price of gas, and thus it provides absolutely no benefit to Choices For You customers, since Choices For You customers obtain their natural gas supply from competitive suppliers rather than the Companies. *See* IGS Energy Ex. 2.0 at 16-17. Indeed, at the Evidentiary Hearing, Ms. Grace admitted that under no circumstances do the Choices For You suppliers benefit from the Companies' hedging strategies. *See* Tr. at 857, 867-873.

In summary, IGS Energy states that the "bottom line" is that Choices For You customers improperly are being charged administrative costs that are caused by the Companies' sales customers. This outcome is directly contrary to generally accepted cost causation principles, which the Commission repeatedly has endorsed. This outcome also results in anti-competitive cross-subsidies and the false price signals that follow. Again, this specifically inconsistent with the pro-competitive policies repeatedly endorsed by the Commission.

Staff

Staff witness Dr. Rearden addressed the recommendation by IGS Energy witness Vincent Parisi that Peoples Gas and North Shore be directed by the Commission to revise their administrative charges to better reflect cost causation principles. IGS Energy Ex. 1.0 at 44. Mr. Parisi made two recommendations. One, IGS Energy was recommending that North Shore and Peoples Gas should stop charging CFY customers for costs that they allegedly do not cause, or in the alternative that CFY customers be given a credit for those costs. Two, that DFY administrative costs are recovered from both sales and transportation customers and not just CFY customers. *Id*. at 5-6. Dr. Rearden testified that:

> [u]tility rate making is a complicated enterprise that involves allocating costs between many different competing groups. There are many examples of costs that the utility incurs that are paid for by all customers but might benefit one group more than another at a point in time. For example, construction in one part of town may have no effect on customers' services in another part of town. There is typically not enough data to disaggregate costs to specific types of customers.

Id. at 4. Dr. Rearden further noted that it is not always clear who the cost causer is. But in the case of the costs of CFY programs, those costs are tracked and are clearly caused by the transportation customers. With respect to the administrative services that Mr. Parisi alleges are mis-allocated to transportation customers, Dr. Rearden argued that those are costs that are not tracked like the CFY costs and it was less clear to him that sales customers are the sole cost causers. Given the above, Staff recommends that the Commission not make any changes as to how rates are calculated for these costs. *Id*. at 8.

Commission Analysis and Conclusions

As the Commission concluded in the preceding section, it was reasonable for the Utilities to make no changes to the administrative charges that the Commission so recently reviewed and approved. The Commission agrees that CFY customers and suppliers benefit from the Utilities' gas supply functions. The fact that CFY customers purchase their gas from an alternative supplier does not mean that no company gas supports the service those customers receive. The Utilities' gas supply function, including hedging, benefits those customers by helping to enable the Utilities to provide a small volume transportation program. The Commission rejects IGS Energy's proposal to remove gas supply functions from rates that CFY customers pay.

3. Recovery of Small Volume Transportation Program (Choices for You^{SM} or "CFY") Administrative Costs

Utilities

The Utilities reiterated their arguments summarized in Sections X.B.1 and X.B.2, *supra*.

IGS Energy

IGS Energy explained throughout the course of this proceeding that one of the uniquely anti-competitive aspects of the Companies' choice program is that the Companies charge administrative costs related to the Choices For You program to only Choices For You customers, through charges directed to the customers' competitive suppliers. The Companies do not take issue with the fact that this design works to inhibit competition; rather, they maintain that since they previously were allowed to implement this anti-choice design, they should be allowed to continue with this structure.

IGS Energy emphasizes that because all customers have the opportunity to access the Choices For You program, and because all customers benefit from the program, regardless of whether they choose to participate in the competitive market, the administrative program costs should be spread across *all customers* who have the option to switch suppliers through the Choices For You program. *See* IGS Energy Ex. 2.0 at 17. IGS Energy notes that this is now the common approach to cost recovery approved by the Commission and advocated by Staff in a variety of contexts. *See Id.* at 22-24; IGS Energy Cross Ex. 7; Tr. at 308.

IGS Energy notes that in the last Ameren gas rate case -- the last opportunity for the Commission to address this issue -- the Commission acknowledged that all customers benefit from being given the opportunity to participate in the choice market:

> The Commission notes that it has long had a policy favoring competition in energy markets, and <u>the Commission believes that customers will generally benefit from being given the opportunity to participate in a well-designed competitive market</u>.

January 10, 2012 Final Order at 193, ICC Docket No. 11-0282, IGS Energy Cross Ex. 2. (emphasis added).

As IGS Energy expert witness Mr. Parisi explained -- exactly consistent with the Commission's view -- all customers receive the option to choose a competitive supplier, and competition benefits *all* ratepayers, regardless of whether a customer remains with the utility or switches suppliers. *See* IGS Energy Ex. 1.0 at 34; IGS Energy Ex. 2.0 at 22-23. Accordingly, as Mr. Parisi recommended, the administrative charge should be spread amongst all eligible customers, resulting in a level playing field for suppliers, given no other costs have been reviewed by the Companies for proper allocation to sales customers, as previously stated. *See Id*.

IGS Energy reiterates that the approach of spreading administrative costs among all customers who have the option to participate:

- Is taken in multiple analogous and related programs and ought to be a non-controversial proposition: it is used by the Companies in their energy efficiency program, where all eligible customers pay the administrative fees, regardless of participation (*see* IGS Energy Ex. 2.0 at 22-24) and the Companies' admit that they did not take issue in this case with the proposition that *all* eligible customers benefit from choice programs (*see* Tr. at 896);
- Is used in Nicor Gas's choice program, and Staff affirmatively supported that view in the 2008 Nicor Gas Rate Case (*see* IGS Energy Cross Ex. 7);
- Is currently being advocated by Staff in the Commonwealth Edison Company Peak Time Rebate Program case (ICC Docket No. 12-0484); Staff did not try to distinguish that approach in its testimony in this case. (*See* Tr. at 308).

IGS Energy observes that consistent with the Companies' anti-choice approach both generally and with regard to the administrative charges issue in this proceeding, the Companies have refused to substantively respond to a proposal intended to benefit customers and repair the competitive market. Instead, in their Initial Brief, the Companies merely assert generally that: (1) the Companies revised their transportation programs in 2011 and 2012; and (2) the Commission decided an administrative charges issue in the Companies' last rate case. *See* Companies Initial Brief at 163-164. IGS Energy notes that the Companies do not, and cannot, maintain that the Commission is prohibited from revisiting the issue; the Companies just claim that since they have been allowed to implement this anti-choice design, they should not be required to change it. Given the continued failings of their choice programs, the Companies' position is not persuasive, according to IGS Energy.

IGS Energy notes Staff response that "in the case of the costs of the [Choices For You] programs, those costs are tracked and are clearly caused by the transportation customers." *See* Staff Initial Brief at 115-116. However, according to IGS Energy, Staff has failed to provide any evidence to substantiate that any of the "costs" to which Staff refers "are clearly caused by the transportation customers." IGS Energy maintains that if anything is clear from the evidence in this proceeding, it is that the Companies do not know who causes many classes of costs and have made no serious attempt to find out. *See* IGS Initial Brief at 6, *citing* Tr. at 847-848; 848; 892; IGS Energy Initial Brief at 15, *citing* IGS Energy Cross Ex. 16, IGS Energy Ex. 2.3; IGS Energy Initial Brief at 19, *citing* IGS Energy Cross Ex. 15. IGS Energy maintains that it is inherently inequitable and contrary to cost causation principles to selectively identify certain costs and allocate those to a subset of customers, while other similar costs are spread among all customers irrespective of causation.

The IGS Energy "bottom line" is that the Companies' current "dumb accounting" system falls far short of the sort of cost causation-determining approach that the Companies and Staff suggest. Other utilities with much more effective choice programs have adopted the approach of spreading the choice program's administrative costs amongst all customers who are given the option to participate, the Commission Staff

and the Commission itself have repeatedly endorsed the approach of spreading administrative costs among all such customers. Thus, IGS Energy states that the Commission ought not to stand idly by; straightforward direction to the Companies to spread administrative costs among all eligible customers would immediately alleviate the problems that are hindering development of competition in the Companies' service territories.

Staff

See X., B., 1.

Commission Analysis and Conclusions

The Commission reiterates its view that that all customers benefit from being given the opportunity to participate in a well-designed competitive market. The benefits of customer choice extend beyond just those customers who actually switch suppliers. All eligible customers benefit from a well-designed competitive program, whether they choose to participate in the competitive market or remain customers of the Companies. Because all eligible retail customers benefit from a competitive program, the costs for running that program should be recovered from all of those eligible customers. Given the cost spreading approach taken in a variety of other analogous contexts -- such as energy efficiency and peak time rebates programs -- this would seem to be a non-controversial position at this point. The Companies are directed to modify their cost recovery methodology for the Choices For You program accordingly.

4. Provider of Last Resort Investigation

Utilities

Utilities witness Ms. Egelhoff stated that, if the Commission chooses to open a proceeding to investigate whether the Utilities should continue to act as the provider of last resort, the Utilities will participate. NS-PGL Ex. 36.0 at 3-4; NS-PGL Ex. 50.0 at 2.

IGS Energy

IGS Energy also requests that the Commission open an investigation of whether the Companies should continue to act as the provider of last resort. IGS Energy points out that there is nothing unique about this concept -- it is being investigated in other states. The need for such an investigation, according to IGS Energy, is highlighted by the Companies' obvious intransigence to even modest changes in the design and implementation of their retail choice program, even in the face of non-controversial evidence that the Companies' Choices For You program is moribund, not only relative to its own past performance, but also in comparison to the retail choice program run by Nicor Gas.

IGS Energy states that the Commission should investigate whether it is necessary or appropriate for the Companies to continue to act as the provider of last

resort. *See* IGS Energy Initial Brief at 8-9, 27-30. At this stage of market development, requiring customers to pay the Companies to perform the default service function is unnecessary and contrary to the pro-competitive principles that the Commission repeatedly has embraced. *See Id.*

In its Initial Brief, IGS Energy explains that under the historic "provider of last" resort model, the incumbent public utility (in this case, the Companies in each of their respective service territories) acts as the "default" provider of natural gas in all circumstances where a customer is not obtaining its supply of natural gas from an alternative supplier. *See Id*. at 8. This traditional model, however, is neither a necessary condition nor even necessarily a desirable condition for an effectively competitive market -- on the contrary, depending on the circumstances, alternative models in which the incumbent public utility is *not* the provider of last resort may better serve the interests of customers. *See Id*., *citing* IGS Energy Ex. 1.0 at 39-44.

IGS Energy has provided detailed testimony on the provider of last resort issue, explaining in general the benefits of having the utility exit the provider of last resort role as well as the specific reasons why the Commission should be suspect of the Companies continuing to act as the provider of last resort. *See Id*. at 9, *citing* IGS Energy Ex. 1.0 at 42-44; IGS Energy Ex. 2.0 at 25-27. IGS Energy notes that neither the Companies nor Staff took issue with the detailed and particularized information that IGS Energy provided throughout the course of this proceeding. *See Id., citing* Tr. at 924; ICC Staff Ex. 18.0 at 8. In their Initial Briefs, Staff merely restated that the Commission has the authority to conduct a provider of last resort investigation, and the Companies reiterated their commitment to fully participate in such an investigation. *See* Staff Initial Brief at 116; the Companies' Initial Brief at 164.

IGS Energy states that given that (1) the Commission's legal authority to conduct a provider of last resort investigation is not in dispute and (2) no party objects to such an investigation, IGS Energy respectfully requests that the Commission initiate a proceeding to investigate whether the Companies should remain the providers of last resort. *See* IGS Energy Initial Brief at 27-30.

IGS Energy notes that in response to IGS Energy's detailed accounting of other state paradigms demonstrating that there are alternative to regulated default service, the Companies stated:

> If the Commission chooses to open a proceeding to investigate the Utilities should continue to act as the provider of last resort, the Utilities will participate.

See NS-PGL Initial Brief at 164. That is the full extent of the Companies' response. Staff responded by stating:

> IGS witness Mr. Parisi recommended that the Commission order an investigation of whether North Shore and Peoples Gas should no longer

> be the provider of last resort ("PLR"). (Staff Ex. 18.0, p. 2) Staff's only comment on the IGS proposal was that if the Commission is interested in the topic at a theoretical level, it could order an investigation. Staff witness Rearden did add that currently North Shore and Peoples Gas are not in a position to surrender their PLR responsibilities.

See Staff Initial Brief at 116. That is the full extent of the Commission Staff's response.

IGS Energy reiterates that it is uncontested that the Commission possesses legal authority to initiate an investigation on provider of last resort and that the Commission has regularly done so with respect to a variety of subjects. *See* IGS Energy Initial Brief at 30. Neither the Companies nor Staff dispute this point. *See Id*. Given that the Companies have taken no steps to advance pro-consumer, pro-competitive programs or accurate cost allocation policies, the Commission should, according to IGS Energy, open a docket to advance the discussion on the Companies' exiting the role of provider of last resort.

Staff

See X., B., 1.

Commission Analysis and Conclusions

The Commission declines, in this rate case for North Shore and Peoples Gas, to open a proceeding to investigate whether North Shore and Peoples Gas should continue to act as the provider of last resort. The Commission notes that, under Section 19-130 of the Alternative Gas Supplier Law, it is submitting a report to the General Assembly, regarding the development of competitive retail natural gas markets in Illinois. As required, the Commission gathered input from interested parties in preparing that report, and it provided a forum for parties to raise the provider of last resort issue.

XI. Findings and Ordering Paragraphs

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Peoples Gas is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Act;

(2) North Shore is an Illinois corporation engaged in the transportation, purchase, storage, distribution and sale of natural gas to the public in Illinois and is a public utility as defined in Section 3-105 of the Act;

(3) the Commission has jurisdiction over the parties and the subject matter herein;

(4) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; the Appendices attached hereto provide supporting calculations;

(5) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2013; such test year is appropriate for purposes of this proceeding;

(6) the $424,299,000 original cost of plant for North Shore at December 31, 2011, and the $3,016,429,000 original cost of plant for Peoples Gas at December 31, 2011 are unconditionally approved as the original costs of plant;

(7) for the test year ending December 31, 2013, and for the purposes of this proceeding, Peoples Gas' original cost rate base with adjustments is $1,463,129,000;

(8) for the test year ending December 31, 2013, and for the purposes of this proceeding, North Shore's original cost rate base with adjustments is $197,594,000;

(9) a just and reasonable return which Peoples Gas should be allowed to earn on its net original cost rate base is 6.70%; this rate of return incorporates a return on common equity of 9.33% and costs of long-term debt of 4.37% and short-term debt of 1.26%, with a just and reasonable capital structure of 50.43% common equity, 43.61% long-term debt and 5.96% short-term debt;

(10) a just and reasonable return which North Shore should be allowed to earn on its net original cost rate base is 6.74%; this rate of return incorporates a return on common equity of 9.33% and costs of long-term debt of 4.53% and short-term debt of 1.80%, with a just and reasonable capital structure of 50.32% common equity, 42.33% long-term debt and 7.35% short-term debt;

(11) Peoples Gas' rate of return set forth in Finding (9) results in approved base rate net operating income of $98,030,000;

(12) North Shore's rate of return set forth in Finding (10) results in approved base rate net operating income of $13,323,000;

(13) pursuant to Section 9-229 of the Act, the Commission has specifically assessed the amounts expended by the Utilities to compensate attorneys and experts to prepare and litigate this general rate case filing and finds those amounts as adjusted to be just and reasonable, with the

Commission's more detailed supporting findings on this subject set forth in Section V.C.9 of this Order;

(14) Peoples Gas' rates, which are presently in effect, are insufficient to generate the operating income necessary to permit Peoples Gas the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(15) North Shore's rates, which are presently in effect, are insufficient to generate the operating income necessary to permit North Shore the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(16) the specific rates proposed by Peoples Gas in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; Peoples Gas' proposed rates should be permanently canceled and annulled consistent with the findings herein;

(17) the specific rates proposed by North Shore in its initial filing do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; North Shore's proposed rates should be permanently canceled and annulled consistent with the findings herein;

(18) Peoples Gas should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $599,309,000, in addition to $16,195,000 of other revenues, which represents a total base rate increase of $52,025,000 or 9.51% in base rate revenues; such revenues will provide Peoples Gas with an opportunity to earn the rate of return set forth in Finding (9) above; based on the record in this proceeding, this return is just and reasonable;

(19) North Shore should be authorized to place into effect tariff sheets designed to produce annual base rate revenues of $82,233,000, in addition to $1,610,000 of other revenues, which represents a base rate increase of $6,139,000 or 6.74% in base rate revenues; such revenues will provide North Shore with an opportunity to earn the rate of return set forth in Finding (10) above; based on the record in this proceeding, this return is just and reasonable;

(20) it is further ordered that the uncollectibles expense includes in base rates for People Gas is $19,813,000 and for North Shore is $799,000;

(21) the determinations regarding cost of service and rate design contained in the prefatory portion of this Order are reasonable for purposes of this proceeding; the tariffs filed by North Shore and Peoples Gas should incorporate the rates and rate designs set forth and referred to herein;

(22) the percentage of fixed costs for purposes of computations under Rider VBA shall be 100% for each of North Shore and Peoples Gas and North Shore and Peoples Gas shall file revised Rate Case Revenues for Rider VBA;

(23) as required in this Order, under the discussion of Uniform Numbering of Service Classifications in Rate Design, North Shore shall conform its service classification numbering to Peoples Gas' format, to the extent applicable, and make all tariff changes necessary to implement this proposal in its compliance filing;

(24) as required in this Order, under the discussion of Service Classification No. 2, General Service, the Utilities shall examine the number and size of distribution charge rate blocks for S.C. No. 2 in their next rate case filings;

(25) as required in this Order, under the discussion of Rider SSC, Storage Service Charge, North Shore and Peoples Gas shall file Rider SSC charges (Storage Banking Charge and Storage Service Charge) consistent with the approved revenue requirements; and

(26) new tariff sheets authorized to be filed by this Order should reflect an effective date consistent with the requirements of Section 9-201(b) as amended.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets presently in effect of The Peoples Gas Light and Coke Company and North Shore Gas Company that are the subject of this proceeding are hereby permanently canceled and annulled, effective at such time as the new tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general rate increase, filed by The Peoples Gas Light and Coke Company and North Shore Gas Company on July 31, 2012, are permanently canceled and annulled.

IT IS FURTHER ORDERED that the $3,016,429,000 original cost of plant for Peoples Gas at December 31, 2011, reflected on Peoples Gas' NS-PGL Ex. 27.14P, Line 19, Column B, is unconditionally approved as the original cost of plant. It is also ordered that the $424,299,000 original cost of plant for North Shore at December 31, 2011, reflected on North Shore's NS-PGL Ex. 24.14N, Line 17, Column B, is unconditionally approved as the original cost of plant.

IT IS FURTHER ORDERED that The Peoples Gas Light and Coke Company and North Shore Gas Company are authorized to file new tariff sheets with supporting workpapers in accordance with Findings (18) and (19) of this Order, applicable to service furnished on and after the effective date of said tariff sheets, which date shall be no later than four business days after said sheets are filed.

IT IS FURTHER ORDERED that North Shore shall conform its service classification numbering to Peoples Gas' format, to the extent applicable, and make all tariff changes necessary to implement this proposal in its compliance filing.

IT IS FURTHER ORDERED that Peoples Gas and North Shore shall file revised Rider VBA Rate Case Revenue amounts and set the percentage of fixed costs for purposes of computations under Rider VBA at 100%.

IT IS FURTHER ORDERED that North Shore and Peoples Gas shall file Rider SSC charges (Storage Banking Charge and Storage Service Charge) consistent with the approved revenue requirements.

IT IS FURTHER ORDERED that North Shore and Peoples Gas examine the number and size of distribution charge rate blocks for S.C. No. 2 in their next rate case filings.

IT IS FURTHER ORDERED that any motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

DATED:	April 26, 2013
BRIEFS ON EXCEPTIONS DUE:	May 9, 2013
REPLY BRIEFS ON EXCEPTIONS DUE:	May 16, 2013

Glennon P. Dolan
Sonya J. Teague
Administrative Law Judges