STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

NORTH SHORE GAS COMPANY	:	No. 11-0280
	:	
Proposed general increase in rates for gas service.	:	(Cons.)
	:	
THE PEOPLES GAS LIGHT AND COKE COMPANY	:	No. 11-0281
	:	
Proposed general increase in rates for gas service.	:	

INITIAL POST-HEARING BRIEF OF NORTH SHORE GAS COMPANY AND THE PEOPLES GAS LIGHT AND COKE COMPANY

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North Shore Gas Company ("North Shore") and The Peoples Gas Light and Coke Company ("Peoples Gas") (together the "Utilities"), by their counsel, pursuant to the schedule ordered by the Administrative Law Judges, submit this Initial Post-Hearing Brief.

I. INTRODUCTION

A. Overview/Summary

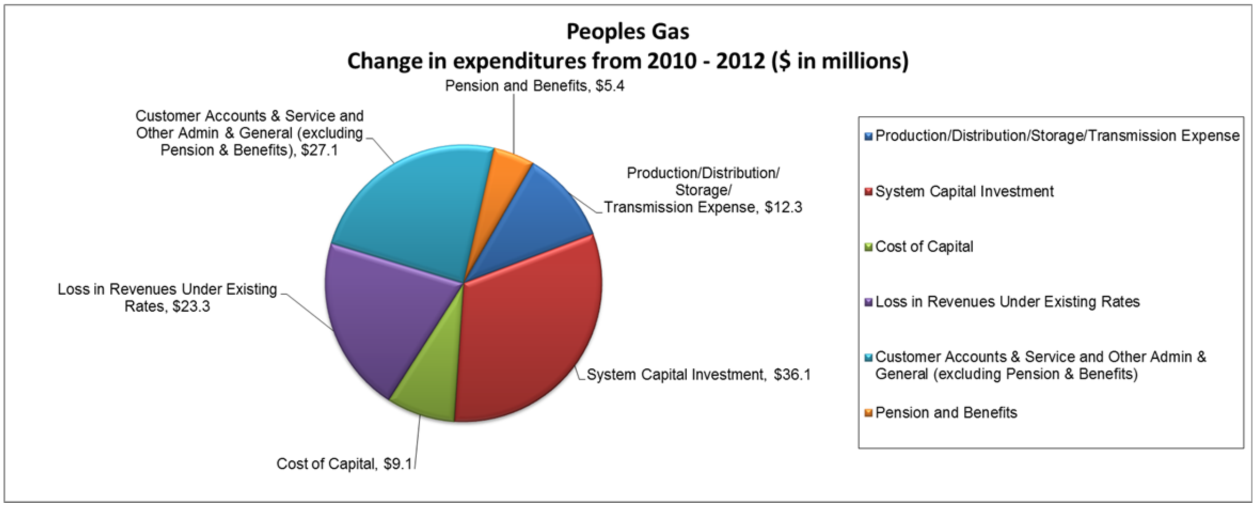
The Illinois Commerce Commission ("Commission" or "ICC") must set rates that allow utilities the opportunity to recover fully their prudent and reasonable costs of service, including costs of capital. That is a legal mandate and it is in the long-term interests of customers.

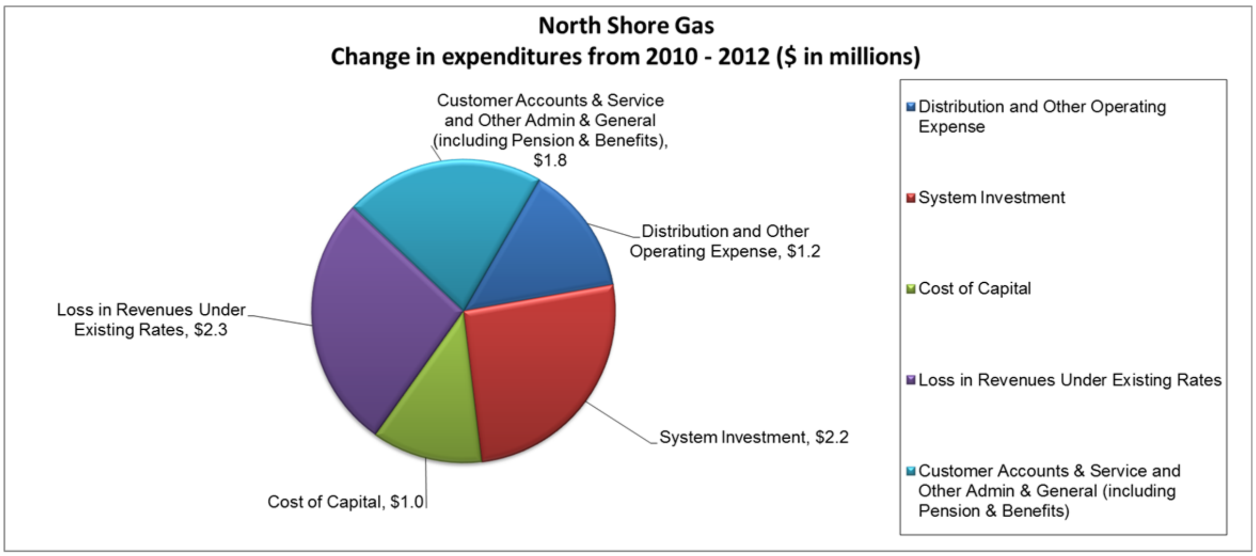
1. The Utilities Will Have Large Cost Recovery Shortfalls in 2012

The Utilities have shown that their existing rates recover less than their actual costs of service, and that the shortfalls ("revenue deficiencies") will reach $110,928,000 for Peoples Gas and $8,214,000 for North Shore (base rate revenue figures) in the 2012 test year.[1]

The Utilities also have shown the drivers of their cost recovery shortfalls compared with the revenue requirements approved in their 2009 rate cases, as illustrated by the following charts:

[1] *E.g.,* Moy Surrebuttal ("Sur."), NS-PGL Exhibit ("Ex.") 39.0 Corr., 14:284-293.





Schott Rebuttal ("Reb."), NS-PGL Ex. 17.0, 10:210 – 11:242.[2]

As the charts reflect, while the Utilities do propose modest increases in the overall rates of return ("ROR") approved in their 2009 cases, from 8.05% to 8.11% for Peoples Gas, and from 8.19% to 8.50% for North Shore,[3] their proposed RORs are a relatively small driver of their cost recovery shortfalls. The larger drivers are their investments in the systems they use to serve

[2] The figures in the above charts do not reflect the Utilities' surrebuttal revisions to their proposed revenue requirements, but the resulting changes in the charts would be relatively limited.

[3] *North Shore Gas Co., et al.*, ICC Docket Nos. 09-0166/09-0167 (Cons.) (Order Jan. 22, 2010) ("*Peoples 2009*"), pp. 129-130; NS-PGL Exs. 35.4P and 35.4N.

customers, customer service and administrative expenses, distribution and transmission expenses, and decreased revenues.

2. Staff's and GCI's Proposed RORs Are Punitive

Staff and GCI[4] propose adjustments that would reduce the Utilities' revenue requirements far below their real costs of service. Because the evidence so strongly supports the Utilities' rising expenses, Staff and GCI must rely primarily on proposals to sharply reduce the Utilities' overall returns on rate base (RORs). These RORs are based on rates of return on common equity ("ROEs") that are <u>below any ROE the Commission has authorized for natural gas utilities since at least 1972</u>, and <u>lower than any ROE any state commission has authorized any energy utility in at least the last 20 years except one</u>. *See* Section VI.E of this Initial Brief. Staff, in a significant departure from its positions in the Utilities' last two rate cases, also proposes to reduce the Utilities' RORs further by imputing significantly weaker capital structures. *See* Section VI.B.

Staff thus proposes a no-win situation for the Utilities and their customers: that the Commission significantly <u>increase</u> the Utilities' <u>risk</u> while at the same significantly <u>decreasing</u> the <u>capital costs</u> they can recover. Indeed, Staff and GCI would readily accept downgrades in the Utilities' credit ratings if the Commission adopted their proposals.[5] Staff's and GCI's use of cost of capital as a tool to artificially reduce the Utilities' 2012 rates would therefore expose the Utilities and their customers to higher risk and higher capital costs in the future.[6] The Commission should not accompany Staff and GCI down this dangerous path, which could lead to real damage to the Utilities' financial standing and over time to increased rates borne by customers.

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[4] The Illinois Attorney General's Office (the "AG"), Citizens Utility Board ("CUB"), and City of Chicago ("City").

[5] Kight-Garlisch Tr., 8/31/11, 406:8-22; Thomas Tr. 9/6/11, 952:21 – 953:7.

[6] *See* Thomas Tr. 9/6/11, 953:18 – 954:5 (conceding that any credit downgrade would increase the Utilities' capital costs, all other things held equal).

The significance of using capital costs to drive rates below the level needed to recover the Utilities' costs of service cannot be overstated. Fully two-thirds of the total difference between the Utilities' revenue requirements and what Staff proposes is due to Staff's ROR proposals. With respect to Peoples Gas, $45,989,000 out of a total $65,270,000 in revenue reductions is due to Staff's proposed ROR of 6.39%, and as to North Shore, $4,681,000 out of a total $8,304,000 in revenue reductions is due to Staff's proposed ROR of 7.08%.[7] Almost half of the total difference between the Utilities' revenue requirements and what GCI proposes is due to GCI's ROR proposals.[8]

The following table illustrates the extremely large reductions in ROEs and RORs proposed by Staff and GCI in the instant cases compared to what the Commission ordered in the Utilities' 2007 and 2009 rate cases and the Utilities' modest increase proposals here.

Source	**PGL ROR**	**PGL ROE**	**NSG ROR**	**NSG ROE**
Feb. 2008 Order in 2007 Rate Cases (*Peoples 2007*) (p. 100)[9]	7.76%	10.19%	7.96%	9.99%
Jan. 2010 Order in 2009 Rate Cases (*Peoples 2009*) (pp. 129-130)	8.05%	10.23%	8.19%	10.33%
2011 **Utilities** Proposals (NS-PGL Exs. 35.4P and 35.4N)	8.11%	10.85%	8.50%	10.85%
2011 **Staff** Proposals (Kight-Garlisch Reb., Staff Ex. 13.1, Sched. 13.1)	6.39%	8.75%	7.08%	8.75%
2011 **GCI** Mid-Point Proposals (GCI Ex. 6.1, Scheds. LKM-1 PGL and NS, p. 2 of 2; Thomas Reb., GCI Ex. 6.0, 14:342-343)	6.678% (mid-point of 6.160% to 7.196%)	8.02% (mid-point of 7.09% to 8.94%)	6.908% (mid-point of 6.390% to 7.426%)	8.02% (mid-point of 7.09% to 8.94%)

[7] Kahle Reb., Staff Ex. 10.0 Corr., Schedules ("Sched.") 10.1P Corr., p. 1, line 24, 10.5P Corr., line 7, 10.1N Corr., p. 1, line 24, 10.5N Corr., line 7.

[8] Unlike Staff, GCI did not present figures that expressly set forth how much of the revenue reductions resulting from its proposed adjustments are due to its ROR proposals. Based on GCI Ex. 6.1, Schedules LKM-1 NS and LKM-1 PGL, it appears that about 42% of the reductions for Peoples Gas and about 44% of the reductions for North Shore are due to GCI's ROR proposals.

[9] *North Shore Gas Co., et al.*, ICC Docket Nos. 07-0241/07-0242 (Cons.) (Order Feb. 7, 2008) ("*Peoples 2007*").

Staff and GCI arrive at their unrealistic RORs through the use of inconsistent methodologies that reflect their subjective opinions on what the Utilities' cost of capital should be, without regard to the realities of the financial markets in which the Utilities compete for capital. Staff proposes to weaken the Utilities' capital structures based on a subjective and erroneous comparison of the Utilities' financial risks to that of the Gas Group, the group of publicly traded gas utilities assembled to determine the Utilities' cost of equity. Staff also proposes a cost of long-term debt for Peoples Gas that includes $51 million in debt that was retired two years ago. Staff's continued search for a methodology that artificially suppresses the Utilities' ROE is revealed by the facts that, in this, the third set of rate cases for the Utilities since 2007, Staff used its third different ROE methodology.

There is one constant, however. In all three rate cases, Staff and GCI chose models and inputs that produced returns on equity far lower than any potential investor in the Utilities would reasonably expect. Both continue to argue that the Commission should give little if any consideration to how the financial markets would react to such extremely low returns, in spite of Constitutional requirements, decades of Commission decisions and the realities of modern finance underscoring that those markets set the costs of the Utilities' capital regardless of Staff's and GCI's opinions about what those the costs should be.

In these cases, Staff used an additional extraordinary tactic. Just two weeks before the hearing, Staff attempted to shore up its ROR position by introducing a new analysis. This "principal components analysis" purported to show that the investment risk of Peoples Gas was lower than, and that the investment risk of North Shore was comparable to, the investment risk of the Gas Group. This new construct not only appeared on the eve of trial, but it also contradicted Staff's position on direct that the Gas Group was as a reasonable proxy for the investment risk of both Utilities. Moreover, Staff produced this analysis without disclosing the equations used to create its inputs, the data used in those equations or the instructions Staff gave the SAS statistical software to perform the analysis. This made it impossible for the Utilities to fully understand, test or evaluate Staff's analysis. Even without that information, the Utilities showed on cross-examination that Staff's analysis does not meet some of the basic requirements of a principal components analysis, and as such is invalid. The Commission should reject entirely this belated and flawed attempt to bolster Staff's extraordinarily low RORs.

The Utilities, by contrast, have proposed modest increases in their RORs that are based on the same methodologies and types of market data on which they relied in their last two rate cases. The Utilities propose the same capital structure that the Commission authorized in their last two rate cases and that they have consistently maintained over the last several years. They propose a modest increase in their ROEs to reflect the continuing volatility and uncertainty in the financial markets following the 2008 credit crisis and the ensuing economic recession. Now is not the time to be weakening the Utilities' financial strength by increasing the leverage and risk in their capital structures and reducing their authorized returns.

3. GCI's Punitive Proposed Reduction of AMRP Costs

Peoples Gas' rate base reflects the expected costs of ramping up its Accelerated Main Replacement Program ("AMRP") in 2011-2012, subject to the proviso that, because Peoples Gas's rate base uses an "average rate base" calculation,[10] only half of the 2012 AMRP investment costs are included in rate base to begin with. Staff accepted Peoples Gas' updated AMRP costs. GCI has done customers a disservice, however, by proposing to remove a net

[10] Hengtgen Direct ("Dir."), PGL Ex. 7.0, 4:71-83.

$54,376,000 of the 2011-2012 AMRP costs that were included in rate base.[11] In the 2009 rate cases, the Commission determined that Peoples Gas' accelerated main replacement plan benefits customers. The effect of GCI's adjustment, if adopted, however, would be to delay accelerated main replacement and increase its costs, both to the long-term detriment of customers. Peoples Gas still plans to spend the revised 2011-2012 total amount on AMRP that is reflected (subject to the average rate base method) in its surrebuttal.[12] However, Peoples Gas cannot do so if that means being denied millions of dollars of recovery of the costs of the AMRP for this period, and instead, in that event, Peoples Gas would have to limit the 2011-2012 expenditures to what the Commission allows, resulting in delay and higher costs.[13] GCI's proposal should be rejected.

4. <u>Rider VBA Should Be Made Permanent</u>

The Utilities' successful pilot decoupling rider, Rider VBA, should be made permanent, a position Staff supports. The Commission's grounds for approving Rider VBA as a pilot in the 2007 cases included the long-term decline and highly variable patterns in usage per customer due to many factors, including increased conservation, energy efficiency, weather, and prices.[14] The rider trues up the costs recovered through volumetric charges (nearly all are fixed costs, *i.e.*, unrelated to the level of consumption of the commodity) for small residential and general service customers. The rider has performed as intended. Staff supports making it permanent, with some revisions, most of which the Utilities accepted.

Unlike Staff, GCI opposes making the rider permanent. GCI opposed the rider in the 2007 rate cases, claiming that it was a one-sided surcharge. Now that the rider has resulted in

[11] GCI Ex. 6.1, Sched. LKM-2 PGL, p. 2.
[12] Hayes Sur., NS-PGL Ex. 42.0 (entire).
[13] Schott Reb., NS-PGL Ex. 17.0, 14:290 - 15:302. Based on GCI's original proposed reduction of $129 million of AMRP costs (gross amount) in 2011-2012 (Effron Dir., GCI Ex. 2.0 Corr., 6:112-120), Peoples Gas would lose approximately $11 million per year until the implementation of rates after its next rate case. Schott Reb., NS-PGL Ex. 17.0, 14:296-299.
[14] *See Peoples 2007*, pp. 150-153.

adjustments that have credited a net $22.9 million to Peoples Gas customers and a net $4.7 million to North Shore customers,[15] GCI relies on erroneous theoretical objections to the rider. GCI misconceives the purposes of the rider, and assumes flawed hypothetical situations while ignoring what the Commission actually said and actual experience. GCI's position is even more problematic because it wants to move more fixed costs from customer charges into volumetric charges, and yet simultaneously argues against truing up the recovery of these costs as to these classes. The real point, however, is not whether the rider made positive or negative adjustments. The real point is whether the rider has worked as the Commission intended. The rider has done so and should be made permanent.

B. Nature of Operations

1. North Shore

North Shore is engaged in the business of transporting, purchasing, storing, distributing and selling natural gas at retail to approximately 159,000 residential, commercial, and industrial customers within 54 communities in Lake and Cook Counties, Illinois. This service territory covers about 275 square miles. The company owns approximately 2,297 miles of gas distribution mains and approximately 95 miles of transmission lines. North Shore employed approximately 162 people at the time these cases were filed. It is a wholly-owned indirect subsidiary of Integrys Energy Group, Inc. ("Integrys"). Schott Dir., NS Ex. 1.0, 5:96-102.

2. Peoples Gas

Peoples Gas is engaged in the business of transporting, purchasing, storing, distributing and selling natural gas at retail to approximately 816,000 residential, commercial, and industrial customers within the City of Chicago. This service territory covers about 237 square miles and

[15] Grace Sur., NS-PGL Ex. 45.0, 19:383 – 23:471.

has a population of approximately three million people. The company owns approximately 4,086 miles of gas distribution mains and approximately 425 miles of transmission lines. Peoples Gas also owns a gas storage field, Manlove Field. Peoples Gas employed approximately 1,076 people at the time these cases were filed, nearly all within the City of Chicago. It is a wholly-owned indirect subsidiary of Integrys. Schott Dir., PGL Ex. 1.0, 5:96-103.

II. <u>TEST YEAR</u> (Uncontested)

The Utilities proposed calendar year 2012, the twelve months ending December 31, 2012, as their test year. Moy Dir., NS Ex. 6.0, 4:87 – 5:99; Moy Dir., PGL Ex. 6.0, 4:87 – 5:99. The 2012 test year data were based on the Utilities' forecasted 2012 revenues, expenses, and rate bases, subject to appropriate adjustments.[16] The proposed test year is uncontested.

III. <u>REVENUE REQUIREMENT</u>

The basic legal standards here are lomg-standing. **<u>The Cost Recovery Principle</u>**. 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.[17] 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

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[16] Moy Dir., NS Ex. 6.0, 4:88-5:99; 6:130-131; Gregor Dir., NS Ex. 5.0, 4:89-5:91; Moy Dir., PGL Ex. 6.0, 4:88-89; 6:130-131; Gregor Dir., PGL Ex. 5.0, 4:89-5:91.

[17] *E.g., Duquesne Light Co. v. Barasch*, 488 U.S. 299, 309-310 (1989); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 622 (1944); *Bluefield Water Works & Improvement Co. v. Public Service Comm'n of the State of West Virginia*, 262 U.S. 679, 693 (1923); U.S. Const., amend. V, XIV (due process and takings clauses); Ill. Const., art. I, §§ 2, 15 (same); *Commonwealth Edison Co. v. Illinois Commerce Comm'n,* 322 Ill. App. 3d 846, 849, 751 N.E.2d 196, 199 (2d Dist. 2001) ("*ComEd*") (citing *Citizens Utilities Co. v. Illinois Commerce Comm'n*, 124 Ill. 2d 195, 200, 529 N.E.2d 510, 512 (1988) ("*Citizens Utilities*"); *see also Citizens Utility Board v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 121, 651 N.E.2d 1089, 1095 (1995) ("*CUB*") (involving costs recovered under a rider).

necessary for the proper discharge of its public duties." *Bluefield,* 262 U.S. at 693. 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." *Hope,* 320 U.S. at 603. 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), p. 41.

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. Schott Dir., PGL Ex. 1.0, 3:58-63; Schott Dir., NS Ex. 1.0, 3:58-63.

Just and Reasonable Rates. 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. *E.g., 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) ("*BPI II*").

The Revenue Requirement Formula. The formula for determining a utility's costs of service, its revenue requirement, is well established. RR = OE + (ROR x RB). The revenue requirement ("RR") equals: (1) its operating expenses ("OE") plus (2) a reasonable rate of return ("ROR") on its rate base ("RB").[18] *E.g., ComEd*, 322 Ill. App. 3d at 849, 751 N.E.2d at 199.

A. North Shore

North Shore's existing rates fall short of allowing it to recover fully its costs of service, as discussed in Section I.A.1 of this Initial Brief. North Shore's comprehensive direct case

[18] The "return of", as opposed to the "return on", capital investments is to be recovered through the depreciation and amortization expenses component of operating expenses.

supported in detail a base rate revenue requirement[19] of $83,313,000, which meant that its cost recovery shortfall (its revenue deficiency) under existing rates in the 2012 test year, which begins less than four months from now, would be $8,594,000. Moy Dir., NS Ex. 6.0, 6:114-116; NS Ex. 6.1 at Sched. C-1, line 5. The drivers of the cost under-recovery as updated in rebuttal are referenced in the first chart in Section I.A.1 and they were discussed in much greater detail in direct and rebuttal testimony.[20] The extensive evidence supporting North Shore's rate base, operating expenses, and rate of return is discussed in Sections IV, V, and VI, *infra*, respectively.

North Shore's detailed rebuttal testimony supported a revised base rate revenue requirement of $83,579,000, with a reduced cost recovery shortfall under current rates of $8,409,000. NS-PGL Ex. 22.1N 2 Corr. at Sched. C-1, line 5. The revisions reflected that North Shore, in its rebuttal, agreed with or accepted in order to narrow the issues, in whole or in part, a number of Staff's and GCI's proposed adjustments, and updated certain items, including, among others, a reduced proposed ROR reflecting a reduced proposed ROE. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 2:38-40, 2:44-3:47; NS-PGL Ex. 22.2N 2 Corr. at Sched. C-2; NS-PGL Ex. 18.1N.

Finally, North Shore's detailed surrebuttal testimony supported a revised base rate revenue requirement of $83,384,000, with a further reduced cost recovery shortfall under current rates of $8,214,000. Moy Sur., NS-PGL Ex. 39.0 Corr., 3:52-58; NS-PGL Ex. 39.1N at Sched.

[19] Consistent with the revenue requirement formula discussed above, each utility's base rate revenue requirement is the sum of (1) its base rate operating expenses plus (2) its operating income requirement. *E.g.,* NS Ex. 6.1 at Sched. C-1, line 5, equals line 33 plus line 34 less line10; PGL Ex. 6.1 at Sched. C-1, line 5 equals line 33 plus line 34 less line10. The operating income requirement number is simply the product of multiplying the utility's rate base by its cost of capital. *E.g.,* NS Ex. 6.1 at Sched. A-2, lines 1-7, and Sched. C-1, line 33; PGL Ex. 6.1 at Sched. A-2, lines 1-7, and Sched. C-1, line 33.

The revenue requirement figures for North Shore and Peoples Gas discussed in this Initial Brief do not include the Cost of Gas recovered under Rider 2 or any costs recovered under Riders 11, EEP, UEA, or VBA, or Rider FCA (North Shore only Rider), or Rider ICR (Peoples Gas only Rider). *E.g.,* Moy Dir., NS Ex. 6.0, 2:36-40; Moy Dir., PGL Ex. 6.0, 2:36-40.

[20] Schott Dir., NS Ex. 1.0, 9:194-11:232; Schott Reb., NS-PGL Ex. 17.0, 11:225-12:242; Gregor Dir., NS Ex. 5.0, 11:235-13:286 (Account variances discussion).

C-1, line 5. The additional reductions reflected that North Shore, in its surrebuttal, again agreed with or accepted, in whole or in part, certain Staff-proposed adjustments and updated certain items. Moy Sur., NS-PGL Ex. 39.0 Corr., 2:37-39, 4:80-83; NS-PGL Ex. 39.2N at Sched. C-2.

The Commission should approve North Shore's final revised revenue requirement. North Shore is entitled to recover these proven costs. The remaining contested adjustments proposed by Staff or GCI are not correct, as discussed in Sections IV, V, and VI, *infra*.

B. Peoples Gas

Peoples Gas' existing rates fall far short of allowing it to recover its costs of service, as discussed in Section I.A.1 of this Initial Brief. Peoples Gas' comprehensive direct case supported in detail a base rate revenue requirement of $613,779,000, which meant that its cost recovery shortfall under existing rates as of the 2012 test year, now less than four months away, would be $123,652,000. Moy Dir., PGL Ex. 6.0, 6:114-116; PGL Ex. 6.1 at Sched. C-1, line 5. The drivers of the cost under-recovery are referenced in the second chart in Section I.A.1 of this Initial Brief and they were discussed in much greater detail in direct and rebuttal testimony.[21] The extensive evidence supporting Peoples Gas' rate base, operating expenses, and rate of return is discussed in Sections IV, V, and VI, *infra*, respectively.

Peoples Gas' detailed rebuttal testimony supported a lower base rate revenue requirement of $601,734,000, meaning its test year cost recovery shortfall under current rates would be decreased to $111,607,000. NS-PGL Ex. 22.1P 2 Corr. at Sched. C-1, line 5. The decreases reflected that Peoples Gas, in its rebuttal, agreed with or accepted in order to narrow the issues, in whole or in part, a number of Staff's and GCI's proposed adjustments, and updated certain items, including, among others, a reduced proposed ROR reflecting a reduced proposed ROE.

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[21] Schott Dir., PGL Ex. 1.0, 9:200-12:245; Schott Reb., NS-PGL Ex. 17.0, 10:204-11:224; Gregor Dir., PGL Ex. 5.0, 11:241-14:302 (Account variances discussion).

Moy Reb., NS-PGL Ex. 22.0 2 Corr., 2:38-40, 2:44-3:47, 4:75-5:100; NS-PGL Ex. 22.2P 2 Corr. at Sched. C-2; NS-PGL Ex. 18.1P.

Finally, Peoples Gas' detailed surrebuttal testimony supported a further-reduced base rate revenue requirement of $601,055,000, meaning its test year cost recovery shortfall under current rates would be decreased to $110,928,000. Moy Sur., NS-PGL Ex. 39.0 Corr., 3:52-58; NS-PGL Ex. 39.1P Corr. at Sched. C-1, line 5. The additional reductions reflected that Peoples Gas, in its surrebuttal, again agreed with or accepted, in whole or in part, certain Staff-proposed adjustments and updated certain items. Moy Sur., NS-PGL Ex. 39.0 Corr., 2:37-39, 3:43-45, 4:77-83; NS-PGL Ex. 39.2P Corr. at Sched. C-2.

The Commission should approve Peoples Gas' final revised revenue requirement. Peoples Gas is entitled to recover these proven costs through its rates. Staff's and GCI's contested proposed adjustments are erroneous, as discussed in Sections IV, V, and VI, *infra*.

IV. RATE BASE

A. Overview/Summary/Totals

1 and 2. North Shore and Peoples Gas

North Shore's surrebuttal presented a rate base of $192,562,000, 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. Hengtgen Sur., NS-PGL Ex. 40.0 Corr., 15:287-291; NS-PGL Ex. 40.1N (Sched. B-1); NS-PGL Ex. 40.2N (Sched. B-2).

Peoples Gas' surrebuttal presented a rate base of $1,472,853,000, 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. Hengtgen Sur., NS-PGL

Ex. 40.0 Corr., 15:287-291; NS-PGL Ex. 40.1P Corr. (Sched. B-1); NS-PGL Ex. 40.2P Corr. (Sched. B-2).

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);[22] Edward Doerk (key components of Gross Utility Plant);[23] Christine Gregor (the test year forecast, including the Capital Budget);[24] Noreen Cleary (capitalized incentive compensation costs);[25] Christine Phillips (updating the pension and OPEB liability figures and the pension asset);[26]and, as to Peoples Gas in particular, Thomas Puracchio (certain capital projects)[27] and Phillip M Hayes (certain capital projects)[28].

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

1. Natural Gas Prices – Working Capital Allowance - Gas in Storage

The Utilities, Staff, and GCI agree to the Utilities' proposed reductions to the Gas in Storage valuations in rate base in order to reflect an updated gas price.[29]

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22 Hengtgen Dir., NS Ex. 7.0; NS Ex. 7.1; Hengtgen Dir., PGL Ex. 7.0; PGL Ex. 7.1; Hengtgen Reb., NS-PGL. Ex. 23.0 Corr.; NS-PGL Exs. 23.1N, Corr., 23.2N Corr., 23.3N, 23.4N, 23.5N, 23.6N, 23.7N, 23.8N Corr., 23.9N, 23.10N; 23.11N, 23.12N Corr., 23.13, 23.14, 23.15, 23.16; 23.17, 23.18N,; 23.1P Corr., 23.2P Corr., 23.3P, 23.4P, 23.5P, 23.6P, 23.7P; 23.8P Corr., 23.9P, 23.10P, 23.11P, 23.12P Corr., 23.18P; Hengtgen Sur., NS-PGL Ex. 40.0 Corr.; NS-PGL Exs. 40.1N, 40.2N, 40.3N, 40.4N, 40.5N, 40.7, 40.1P Corr., 40.2P Corr., 40.3P Corr., 40.4P Corr., 40.5P Corr., 40.6P, 40.7.

23 Doerk Dir., NS Ex. 8.0; NS Ex. 8.1; Doerk Dir., PGL Ex. 8.0 (except 9:174-13:281); PGL Ex. 8.1; Doerk Reb., NS-PGL Ex. 24.0 (except page 6:104-108); Doerk Sur., NS-PGL Ex. 41.0.

24 Gregor Dir., NS Ex. 5.0; NS Ex. 5.1; Gregor Dir., PGL Ex. 5.0; PGL Ex. 5.1; Gregor Reb., NS-PGL Ex. 21.0 Corr.; NS-PGL Exs. 21.1N, 21.2N, 21.3N, 21.1P, 21.2P, 21.3P, 21.4P; Gregor Sur., NS-PGL Ex. 38.0; NS-PGL Exs. 38.2, 38.3N; 38.4N. 38.1P, 38.2, 38.3P; 38.4P.

25 Cleary Dir., NS Ex. 9.0; NS Ex. 9.1; Cleary Dir., PGL Ex. 9.0; PGL Ex. 9.1; Cleary Reb., NS-PGL Ex. 25.0; Cleary Sur., NS-PGL Ex. 43.0; NS-PGL Exs. 43.1, 43.2, 43.3.

26 Phillips Dir., NS Ex. 11.0; NS Exs. 11.1, 11.2; Phillips Dir., PGL Ex. 11.0; PGL Exs. 11.1, 11.2; Phillips Reb., NS-PGL Ex. 27.0; NS-PGL Exs. 27.1N, 27.2N, 27.3N, 27.4, 27.1P, 27.2P, 27.3P, 27.4

27 Puracchio Dir., PGL Ex. 16.0, PGL Exs. 16.1, 16.2, 16.3, 16.4, 16.5, 16.6, 16.7, 16.8, 16.9, 16.10, 16.11, 16.12; Puracchio Reb., NS-PGL Ex. 33.0 Rev.; NS-PGL Exs. 33.1, 33.2.

28 Hayes Dir., PGL Ex. 8.0, 9:174-13:281 (only); Hayes Reb., NS-PGL Ex. 24.0, 6:104-108 (only); Hayes Sur., NS-PGL Ex. 42.0. Please note: Mr. Hayes adopted portions of Mr. Doerk's direct and rebuttal testimony and, therefore, those portions are cited as Mr. Hayes' testimony.

29 Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 7:155-8:164; Seagle Reb., Staff Ex. 17.0, 9:135-10:180; Morgan Reb., GCI Ex. 6.0, pp. 2-3.

2. Plant

a. Specific Plant Investments – Warehouse at Manlove Field

The Utilities and Staff agreed upon the inclusion of the costs of the following projects in rate base: (1) the costs associated with the Pigging and Well-Head Separator Project #1, (2) the costs associated with the Pigging and Well-Head Separator Project #2, (3) the costs associated with the construction of a new warehouse at Manlove Field, and, (4) the costs associated with the Pipeline Heaters Replacement Project.[30] These are not contested.

b, c, and d. Pigging Well-Head Separator Projects #1 and #2 and Pipeline Heaters Replacement Project

See Section IV.B.2.a, *supra*.

3. Accumulated Depreciation Expense on Forecasted Additions and Utility Plant in Service – 2010 Actual

The Utilities and Staff have agreed upon the adjusted depreciation reserve amounts for actual 2010 plant-in-service for both Utilities.[31] This is not contested.

4. Accumulated Deferred Income Taxes

a. Bonus Depreciation, Illinois State Income Taxes and Tax Accounting Method Changes

The Utilities and Staff have agreed to adjustments Regarding Accumulated Deferred Income Taxes ("ADIT") for both Utilities.[32] This is uncontested.

b. Use of Average Rate Assumption Method Relating to Health Care Reform Legislation

The Utilities proposed to re-measure deferred tax balances caused by enactment of the health care reform legislation using the average rate assumption method.[33] This is uncontested.

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[30] Seagle Reb., Staff Ex. 17.0, 5:82-85, 11:208-212, 12:291-295, 13:310-312.
[31] NS-PGL Exs. 23.4N and 23.4P; Kahle Reb., Staff Ex. 10.0, 6:109-113.
[32] NS-PGL Exs. 23.4N and 23.4P; Kahle Reb., Staff Ex. 10.0, 6:114-119.

c. Net Operating Loss – Tax Normalization

The Utilities proposed to calculate their Net Operating Loss at present rates to offset deferred tax liabilities and avoid a normalization violation; a further calculation is needed to reflect NOL normalization based on revenue changes in the final Order.[34] This is uncontested.

C. Contested Issues

1. Plant (All Subjects Relate to NS and PGL Unless Otherwise Noted)

a. Forecasted Test Year Capital Additions

(i) Utility Plant in Service

Staff witness Mr. Kahle proposed an adjustment to reduce the Utilities' forecasted additions to plant-in-service for the years ending December 31, 2011, and December 31, 2012, based on the historical spending pattern for budgeted capital expenditures for 2008, 2009 and 2010. Kahle Dir., Staff Ex. 1.0, 15:317-16:339. The Utilities do not object to Staff's adjustment, as corrected by their surrebuttal testimony. Hengtgen Sur., NS-PGL Ex. 40.0 Corr., 3:57-4:65.

The Commission should approve Staff's proposed adjustment and reject the GCI adjustment discussed below in Section IV.C.1.a.ii of this Initial Brief. As Staff witness Mr. Kahle states, his "analysis provides a better assessment of the Companies' performance because [his] analysis includes all of the Companies' budgeted capital expenditures rather than a single project as does [GCI witness] Mr. Effron." Kahle Dir., Staff Ex. 1.0, 15:323-326. However, if Staff's adjustment is not approved, then the Commission should approve the forecasted plant additions as proposed by the Utilities.

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[33] Stabile Dir., NS Ex. 10.0, 2:36-6:131; Stabile Dir., PGL Ex. 10.0, 2:37-6:131.
[34] Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 6:116-6:126; Stabile Reb., NS-PGL Ex. 26.0, 26:613-26:615; Hengtgen Sur., NS-PGL Ex. 40.0 Corr., 13:263-15:291.

(ii) Capital Additions Related to Accelerated Main Replacement – AMRP (PGL)

GCI proposes to adjust Peoples Gas' forecasted plant-in-service for the years 2011 and 2012 to disallow $54,376,000 of the additions related to the Accelerated Main Replacement Program ("AMRP"), of which $36,036,000 is for 2011 and $18,340,000 is for 2012 (the 2012 figure reflects the utility's use of the average rate base method for the test year). Effron Reb., GCI Ex. 7.0, 3:46-61; GCI Ex. 7.2, Scheds. DJE-1.1; GCI Ex. 6.1, p. 2. Mr. Effron's adjustment should be rejected as it is not based upon the evidence and thus, is without merit.

Mr. Effron's adjustment is based on a flawed premise that Peoples Gas will not complete the work scheduled for 2011, and thus, this under-spending will carry over into the test year. Peoples Gas initially treated the 2011 AMRP expenditures of $123.4 million as if they would be expended evenly over the course of 2011 and budgeted accordingly. However, these expenditures instead reflected a bell shape curve, with fewer costs being incurred in the early and late months of the year and the peak expenditures being in the middle months, which represent the peak construction months. Hayes Sur., NS-PGL Ex. 42.0, 4:78-83. The record demonstrates that for 2011, the first year of the 20 year AMRP, Peoples Gas has experienced the normal transition or "learning curve" with the ramp up of activities such as design, permitting, staffing of key positions, construction contract bidding, etc., that have slightly delayed the expenditures so far this year. *Id.* at 4:84-5:89. By the end of May 2011, there has been a ramp-up of the AMRP expenditures which are expected to climb dramatically for the remainder of 2011 and 2012. Hayes Reb, NS-PGL Ex. 24.0, 6:110-112.

Even though fewer costs were expended in the early months of 2011, Peoples Gas fully intends to achieve the forecasted 2011 expenditures for AMRP as is demonstrated by:

- Peoples Gas has contracted with four installation contractors to install over 180 miles of new mains and over 16,000 services in 2011; and
- Peoples Gas crews are ramping up to complete over 24,000 meter sets in 2011.

Additionally, Peoples Gas has a contingency plan in place should circumstances prevent it from completing this work, which includes the installation of approximately 4 miles of high pressure piping inclusive of the tie-in to the natural gas transmission line along with the necessary valves and regulators. *Id.* at 5:91-99.

Furthermore, GCI's argument that any under spending in 2011 will affect 2012 spending is pure speculation and without merit. 2012, the second year of the AMRP, will benefit from the lessons learned from 2011 and Peoples Gas expects a much earlier start for the 2012 construction year. *Id.* at 5:102-107.

Finally, should the Commission deny Staff's proposed adjustment discussed in Section IV.C.1.a.(i) of this Initial Brief as accepted by the Utilities, and instead approve the GCI adjustment, Peoples Gas would have to limit its capital expenditures to what the Commission allows for the 2011-2012 period. Peoples Gas still plans to spend the revised 2011-2012 total amount on AMRP that is reflected (subject to the average rate base method) in its surrebuttal.[35] However, Peoples Gas cannot do so if that means being denied millions of dollars of recovery of the costs of the AMRP for this period, and instead, in that event, Peoples Gas would have to limit the 2011-2012 expenditures to what the Commission allows, resulting in delay and higher costs.[36] The disallowance of these costs from rate base would delay the AMRP-associated

[35] Hayes Sur., NS-PGL Ex. 42.0 (entire).

[36] Schott Reb., NS-PGL Ex. 17.0, 14:290 - 15:302. Based on GCI's original proposed reduction of $129 million of AMRP costs (gross amount) in 2011-2012 (Effron Dir., GCI Ex. 2.0 Corr., 6:112-120), Peoples Gas would lose approximately $11 million per year until the implementation of rates after its next rate case. Schott Reb., NS-PGL Ex. 17.0, 14:296-299.

customer benefits, including safety and reliability, as described by Mr. Hayes. Hayes Dir., PGL Ex. 8.0, 12:253-13:277.

Staff's corrected proposed adjustment as discussed in Section IV.C.1.a.i of this Initial Brief should be adopted. GCI's adjustment should be rejected.

b. <u>Capitalized Incentive Compensation</u> (See also Section V.C.1)

See Section V.C.1 of this Initial Brief.

c. <u>Non-Union Wages</u> (See also Section V.C.2)

See Section V.C.2 of this Initial Brief.

d. Original Cost Determination as to <u>Plant Balances as of December 31, 2009</u>

Staff witness Mr. Kahle and Utilities witness Mr. Hengtgen are in agreement that the Commission's final Order include an original cost determination of plant for each utility as of December 31, 2009. However, they disagree as to amount. Kahle Dir., Staff Ex. 1.0, 19:404 - 20:436; Kahle Reb., Staff Ex. 10.0 Corr., 19:409-20:432; Hengtgen Dir., NS Ex. 7.0, 15:320-16:337; PGL Ex. 7.0, 17:378-18:395; Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 24:511 - 25:533; Hengtgen Sur., NS-PGL 40.0 Corr., 12:230-237. Mr. Kahle proposes to decrease Peoples Gas' original cost determination figure by $649,000 and decrease North Shore's by $122,000 relating to the capitalized incentive compensation not allowed for recovery in the Utilities' 2007 and 2009 rate cases. This is an issue on appeal from both cases. If the Utilities were to prevail on appeal, the Commission would have inappropriately reduced their original cost of plant. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 24:521-25:533.

Thus, the original cost determination contained in the Commission Order should state:

> It is further ordered that the $411,643,000 original cost of plant for North Shore at December 31, 2009, and the $2,667,949,000 original cost of plant for Peoples Gas

at December 31, 2009, reflected on each Utility's Schedule B-5, Page 1 of 2, are unconditionally approved as the original costs of plant.

However, if the Commission decides to accept Mr. Kahle's proposal, then the final Order should specify that if a decision in the appeals or any other proceeding results in the plant in question being approved, then the Utilities' figures should be approved.

2. Materials and Supplies – Computation of Associated Accounts Payable

Both Staff witness Ms. Ebrey and GCI witness Mr. Morgan proposed adjustments to the computation of accounts payable associated with Material and Supplies. Ebrey Dir., Staff Ex. 3.0, 26:635-27:652; Morgan Dir., GCI Ex. 1.0 Corr., 8:23-10:18. The Utilities did not contest and the Commission should approve Mr. Morgan's methodology to compute accounts payable associated with Materials and Supplies, which is a two-year composite percentage of the monthly debits to materials and supplies accounts that is applied to the test year, as corrected by Utilities witness Mr. Hengtgen. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 11:241-12:245; Morgan Reb., GCI Ex. 6.0, 2. The Commission should reject Staff's methodology for computing as it improperly uses a lead time in days from the Cash Working Capital ("CWC") lead-lag study to calculate what Staff refers to as "reasonable level of costs that would be included in Accounts Payable." Ebrey Dir., Staff Ex. 3.0 Corr., 27:641-642.

The lead-lag study is prepared to determine the level of CWC a utility requires to finance its day to day operations. The CWC requirement is included in a utility's rate base. Hengtgen Dir., NS Ex. 7.0, 16:339-17:362; PGL Ex. 7.0, 18:397-19-421. The CWC requirement does not affect any other rate base component. A lead-lag study measures the amount of time in days that on average it takes a utility to pay for its other operation and maintenance expenses, such as Material and Supplies. Thus, the lead-lag study only applies to expenses and <u>not</u> the portion of the purchases that are included in material and supplies and already are a component of rate base. However, the accounts payable offset is intended to measure the amount of materials and supplies, a rate base item, at month end for which payment has not yet been made. As a result, Staff's calculation computes an amount of accounts payable by utilizing a time period in days. The two are not related and a time period is not an appropriate measure to reflect an amount of accounts payable at month end. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 12:246-258.

GCI witness Mr. Morgan's methodology is more appropriate as it uses a two-year composite percentage of the monthly debits, or monthly increases, recorded to the rate base component, Materials and Supplies. Therefore, the Commission should adopt the GCI adjustment as corrected by Utilities witness Mr. Hengtgen and reject Staff's proposal.

3. Gas in Storage – Computation of Associated Accounts Payable

Gas in Storage is an asset in rate base which the Utilities have offset with related accounts payable based on Commission treatment established in their last two rate cases. Hengtgen Dir., NS Ex. 7.0, 7:139-142; PGL Ex. 7.0, 7:145-148. Consistent with the methodology approved in the 2009 rate cases, the Utilities calculated the associated accounts payable offset amount as the net increase in the monthly Gas in Storage balance. Hengtgen Dir., NS Ex. 7.0, 12:252-254; Hengtgen Dir., PGL Ex. 7.0, 14:309-311. However, Staff witness Ms. Ebrey has proposed another method to calculate the accounts payable for Gas in Storage that is based on the expense leads (in days) for natural gas purchases from the CWC lead-lag study and test year injections. Staff's proposal must be rejected as it fails to reflect how the Utilities' account for Gas in Storage and the use of the lead-lag study is not proper.

Staff's computation of associated accounts payable is flawed because it does not reflect that the Utilities use the Last-In First-Out ("LIFO") method to account for Gas in Storage

Inventory. The LIFO accounting method means that as the Utilities purchase gas to serve customers, the last gas in (purchased) is the first gas out (to customers). Thus, based on the LIFO method, the Utilities do not reflect current year gas purchases in inventory until the beginning of the year volume of gas is restored or replenished back into inventory. For both Peoples Gas and North Shore, this does not occur in the test year until August. From August to November, an amount for current year purchases is reflected in the end of the month inventory balance. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 9:184-191; NS-PGL Exs. 23.6N and 23.6P. That is consistent with the Utilities' methodology, whereby the average in the increase in test-year monthly balances of Gas in Storage is used as the accounts payable offset. In fact, the Utilities' methodology is conservative in that it begins in April 2012 for both Utilities (*see* NS Ex. 7.1 at p. 2; PGL Ex. 7.1 at p. 2) even though the gas purchases are not projected to be recorded to Gas in Storage until August 2012.

However, Ms. Ebrey's methodology calculates accounts payable amounts for all months of the test year except January, 2012. NS-PGL Exs. 23.6N and 23.6P show that for the months January through July and December, the dollar value of gas that comprises the ending balance of Gas in Storage is related to inventory purchased years ago – not the test year. To assign an amount of outstanding accounts payable related to gas that was purchased in years prior to the test year is improper. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 9:184-196.

Further, Staff's reliance on the Ameren Illinois methodology used in its current rate cases, ICC Docket Nos. 11-0279/0281 (cons.), is misplaced because Ameren Illinois uses a different accounting method for Gas in Storage. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 9:197 - 10:207; NS-PGL Ex. 23.15. Instructive is the methodology used in ICC Docket No. 08-0363, Northern Illinois Gas Company's ("Nicor") last rate case. Nicor, which uses the

LIFO accounting method for Gas in Storage, proposed a similar methodology as the Utilities have proposed in this proceeding and it was uncontested in Nicor's rate case. NS-PGL Ex. 23.0 Corr., 10:213 – 11:220. *See also Northern Illinois Gas Co.*, ICC Docket No. 08-0363 (Order Mar. 25, 2009) ("*Nicor 2008*"), p. 16. Noteworthy is that GCI witness Mr. Morgan proposed a similar adjustment as Staff's regarding associated accounts payable for Gas in Storage. Morgan Dir., GCI 1.0 Corr., pp. 10-11. However, upon learning that the Utilities account for Gas in Storage using the LIFO method, Mr. Morgan withdrew his adjustment, stating: "Given the Companies' accounting method, my adjustment would be inappropriate." Morgan Reb., GCI Ex. 6.0, p. 2; *see also* NS-PGL Ex. 23.13.

Finally, just as Staff's Material and Supplies adjustment must be rejected, Ms. Ebrey's calculation here is also flawed because she relies on the lead-lag study. The lead-lag study is prepared to determine the level of CWC a utility requires to finance its day to day operations. The CWC requirement is included in a utility's rate base. Hengtgen Dir., NS Ex. 7.0, 16:339 - 17:362; Hengtgen Dir., PGL Ex. 7.0, 18:397-19-421. The CWC requirement simply does not affect any other rate base component. A lead-lag study measures the amount of time in days that on average it takes a utility to pay for its gas costs expenses. Thus, the lead-lag study only applies to expenses and <u>not</u> the portion of the purchases that are included in inventory and already are a component of rate base. However, the accounts payable offset is intended to measure the amount of Gas in Storage Inventory, a rate base item, at month end for which payment has not yet been made. As a result, Staff's calculation computes an amount of accounts payable by utilizing a time period in days. The two are not related and a time period is not an appropriate measure to reflect an amount of accounts payable at month end. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 11:222-233.

Staff's methodology to calculate accounts payable associated with Gas in Storage inventory is without merit and should be rejected.

4. Cash Working Capital

Cash working capital is the amount of funds required to finance the day-to-day operations of a utility. The CWC requirement is included in each of the Utilities' rate bases for ratemaking purposes. Hengtgen Dir., NS Ex. 7.0, 16:356 – 17:362; Hengtgen Dir., PGL Ex. 7.0, 19:415-421. To determine the cash working capital requirement, a lead-lag study analyzes the differences between the revenue lags and the expense leads of a utility. Three broad categories of leads and lags are considered: (1) lag times associated with the collection of revenues owed to the utility; (2) lag and lead times associated with the collection and payment of what are commonly called "pass-through" taxes and "energy assistance charges" and (3) lead times associated with the payments for goods and services received by the utility. Hengtgen Dir., NS Ex. 7.0, 17:363-375. Hengtgen Dir., PGL Ex. 7.0, 20:423-434. The Utilities performed a lead-lag study closely conforming to the methodology adopted by the Commission in the 2007 and 2009 rate cases. Hengtgen Dir., NS Ex. 7.0, 18:383-389; Hengtgen Dir., PGL Ex. 7.0, 21:423-434.

a. Pass-Through Taxes and Energy Assistance Charges

The only contested aspect of the Utilities' lead-lag cash working capital study relates to pass-through taxes and energy assistance charges. The Utilities add pass-through taxes and energy assistance charges to customer bills and then are required to remit the funds to various local and state governmental agencies. These taxes and charges are not recorded as revenue or expense on the income statement, but their collection and payment cause a timing difference in the cash flow that needs to be accounted for. Hengtgen Dir., NS Ex. 7.0, 21:451-457; Hengtgen

Dir., PGL Ex. 7.0, 24:510–516. In approving the Utilities' expense leads and revenue lags in the 2009 rate cases, the Commission acknowledged and found that: "If shareholders make a payment because the money has not yet been received from ratepayers, then this amount is appropriately contained in the calculation of cash working capital." *Peoples 2009*, p. 24.

Staff, however, proposes to change the methodology, causing a large and unsubstantiated disallowance of a portion of each of the Utilities' cash working capital. Staff's proposal to arbitrarily change the expense lead of two pass-through taxes and energy assistance charges and assign a revenue lag of zero days to pass-through taxes and energy assistance charges is improper and is not supported by the evidence in this proceeding.

(i) Lags for Pass-Through Taxes and Energy Assistance Charges

In a lead-lag study, 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. Hengtgen Dir., NS Ex. 7.0, 19:407-409; Hengtgen Dir., PGL Ex. 7.0, 22:466-468. Pass-through taxes and energy assistance charges 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 pass-through taxes and energy assistance charges is identical to the revenue lag. Hengtgen Dir., NS Ex. 7.0, 22:469-473; Hengtgen Dir., PGL Ex. 7.0, 25:529–533. Staff argues 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. Kahle Dir., Staff Ex. 1.0, 11:220-224. However, the Commission specifically rejected Staff's argument in the Utilities' 2009 rate case, stating:

> The Utilities have appropriately used a methodology that matches what the Commission approved in the Utilities' last rate cases. The evidence shows that the Utilities addressed the actual lags and leads for pass-through taxes in their study. Staff's proposal, however, would in effect find that the Utilities are holding

> customers' money for 50.3 days (Peoples Gas) and 74.82 days (North Shore). Tr. at 750. The evidence does not support this. <u>It appears that Staff's approach improperly ignores the time between when customers are billed for pass through taxes and when the pass through taxes are remitted to the Utilities</u>.

Peoples 2009, p. 24 (emphasis added). Further, Staff agrees that the terms upon which the Utilities remit taxes and charges have not changed since the 2009 rate cases. Kahle Transcript ("Tr.") 8/30/11, 271:21-272-2. Staff's methodology must be rejected again as it is not supported by the record.

Staff's argument that because cash received from customers for pass-through taxes is not a payment for utility service, there should be no revenue lag should be rejected for several reasons. First, Staff is incorrect. Mr. Hengtgen explained in his rebuttal testimony the types of pass-through taxes and energy assistance charges and that these taxes and charges were taxes or charges imposed by law on either the Utilities or the customers and were either collected through a separate charge prescribed by law or described within the statute as a charge for utility service. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 17:352-18:379; 305 ILCS 20/13(e) ("The Energy Assistance Charges assessed by electric and gas public utilities shall be considered a charge for public utility service.")

Second, assuming that Staff were correct that there should be no lag because the cash collected for the pass-through taxes and energy assistance charges is not recorded as revenue, and they are not, then there should also be no expense lead because the taxes are not recorded as expense either. Staff's position is flawed as consistent thinking would require that because they are not recorded as expense, they cannot have an expense lead either. The Utilities in direct testimony (Hengtgen Dir., NS Ex. 7.0, 20:454-457; Hengtgen Dir., PGL Ex. 7.0, 24:513-516), and again in rebuttal (Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 19:404-20:425), have stated that the pass-through taxes are not recorded as revenue or expense but they do create timing issues in the collection and payment of the taxes. That is because the Utilities bill customers for the pass-through taxes in their normal billing process, and the customers do not pay the bills immediately to the Utilities when they receive their bills. Thus, the Utilities appropriately calculated the lead times based on the timing of cash flows in and cash flows out. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 20:418-419. In the 2009 rate cases Order, the Commission acknowledged that "If shareholders make a payment because the money has not yet been received from ratepayers, then this amount is appropriately contained in the calculation of cash working capital." *Peoples 2009*, p. 24. Staff witness Mr. Kahle does not disagree. Kahle Tr. 8/30/11, 269:19-270:8. However, Staff continues to eliminate the cash flow in part of the timing difference but does not correct or adjust downward the lead (cash flow out). Staff's proposal would indicate that the Utilities collect and hold most of the pass through taxes and energy assistance charges for an extremely long period time before remitting them to the appropriate taxing jurisdiction, which is simply not accurate. Furthermore, under Staff's proposal, the Utilities would not be in compliance with the appropriate statutes and ordinances governing the payment of the pass-through taxes and energy assistance charges. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 20:420-425.

Third, Staff argues that the Commission's decisions on this issue have "evolved" based on its Orders in the following rate cases: *Nicor 2008*; *Ameren Illinois*, ICC Docket Nos. 09-0306/0307/0311 (cons.) (Order April 29, 2010) ("*Ameren 2009*"); and *Commonwealth Edison Co.*, ICC Docket No. 10-0467 (Order May 24, 2010) ("*ComEd 2010*"). However, the Commission in the Utilities' 2009 rate cases Order found that:

> This is a factual question that rests on when a utility must make certain payments, such as taxes, and when it receives the cash from ratepayers to the make the payments. Whether the payments are based on estimate or actual cash receipts does not matter. If shareholders make a payment because the money has not yet been received from ratepayers, then this amount is appropriately contained in the calculation of cash working capital. Lead lag studies are the method by which this

> is determined. It is to be expected that each utility's lead-lag study will show different results and, thus, the decision in *Nicor 2008* is not controlling.

Peoples 2009, p. 24 (emphasis added). Thus, because 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, the decisions in *Nicor 2008*, *Ameren 2009*, and *ComEd 2010* are not controlling here. It is true that the companies in *Nicor 2008*, *Ameren 2009*, and *ComEd 2010* are utilities, a gas utility, a combination gas and electric utility, and an electric utility, respectively. However, electric utilities have some different types of taxes imposed on them or their customers, which have different requirements than the taxes being at issue in this proceeding. Further, each of these utilities operate in different parts of the State indicating that there are different municipal utility taxes imposed on them or their customers. Finally, not all utilities remit these types of taxes on the same basis. For example, unlike other utilities, Peoples Gas and North Shore remit these taxes based on estimated collections based on an agreement that Peoples Gas has with the City of Chicago. Hengtgen Sur., NS-PGL Ex. 40.0 Corr., 10:181-11:195. Despite asserting that the Utilities "process pass-through taxes in the same manner" as the utilities in *Nicor 2008*, *Ameren 2009*, and *ComEd 2010* (Kahle Reb., Staff Ex. 10.0 Corr., 10:202-203), Staff witness Mr. Kahle acknowledged he did not compare the local laws or municipal agreements that Nicor, Ameren, or ComEd are subject to with those to which the Utilities are subject. Kahle Tr. 8/30/11, 274:6-10.

Staff's use of zero revenue lag days must be rejected as there is no support in the record for this conclusion or result. Further, it is contrary to the Commission's conclusion in the 2009 rate cases Order, with no basis for a change. While Staff's methodology might have been appropriate in some other utilities' rate cases, it does not reflect the Utilities' facts here.

(ii) Leads for Pass-Through Taxes and Energy Assistance Charges

An expense lead represents the time between when a good is received or a service is provided and when the Utilities pay for that good or service. Hengtgen Dir., NS Ex. 7.0, 24:509-510; Hengtgen Dir., PGL Ex. 7.0, 27:576-577. In direct testimony, Staff witness Mr. Kahle initially agreed with the Utilities' calculation of expense leads for pass-through taxes and energy assistance charges. Kahle Tr. 8/30/11, 265:6-10. However, in rebuttal testimony, Mr. Kahle revised the expense leads for three items, including Energy Assistance Charges, Gross Receipts/Municipal Utility and City of Chicago Gas Use Taxes, because Utilities witness Mr. Hengtgen "offered a revised number of lead days that [the Utilities] collect[] these pass-through taxes before remitting." Kahle Reb., Staff Ex. 10.0 Corr., 7:161-8:180. To support his calculations, Mr. Kahle relies on lines 442-451 on page 21 of Mr. Hengtgen's rebuttal testimony (NS-PGL Ex. 23.0 Corr.). Kahle Tr. 8/30/11, 266:3-9. However, nowhere in Mr. Hengtgen's direct, rebuttal, or surrebuttal testimony does he offer a revised number of lead days that the Utilities collect these pass-through taxes and energy assistance charges before remitting. The testimony upon which Mr. Kahle relies is actually a criticism of Staff's methodology for calculating revenue lag days for pass through taxes. Mr. Kahle acknowledged on cross examination that he "interpreted [Mr. Hengtgen's testimony] as being an altered calculation of the expense lead days" and that Mr. Hengtgen did not revise lead days for these taxes. *Id*. at 266:15 - 267:13.

Staff's revised expense lead days for the three items in question should be rejected as it is not supported by the record and is based on misinterpretation of the Utilities' rebuttal testimony.

The Commission should approve the lags and leads for pass-through taxes and energy assistance charges as proposed by the Utilities.

b. Prepayments (Uncontested)

GCI witness Mr. Morgan and Staff witness Mr. Kahle each proposed a change to the collection lag with respect to prepayments. Morgan Dir., GCI Ex. 1.0 Corr., pp. 7-8; Kahle Dir., Staff Ex. 1.0, 9:170-10:192. In rebuttal testimony, Utilities witness Mr. Hengtgen agreed that an adjustment to the collection lag was appropriate and accepted Staff's adjustment. Mr. Morgan accepted the adjustment in rebuttal testimony. Morgan Reb., GCI Ex. 6.0, p. 3.

c. All Other (Uncontested)

The Utilities, Staff, and GCI agree that the final amount of the Utilities' CWC requirements should be determined based on the revenue and expense levels ultimately approved by the Commission in this proceeding. Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 15:316-318; Kahle Reb., Staff Ex. 10.0 Corr., 8:150-152; Morgan Reb., GCI Ex. 6.0, p. 3.

5. Retirement Benefits, Net

In brief, "Retirement Benefits, Net" for each utility is the sum of its pension asset (its prepaid pension expense) less its "OPEB" (other post-employment benefits) (also sometimes referred to as "post-retirement welfare") liability. NS Ex. 7.1 at Sched. B-1.2; PGL Ex. 7.1 at Sched. B-1.2; Phillips Dir., NS Ex. 11.0, 12:268-271; Phillips Dir., PGL Ex. 11.0, 12:260-263; Effron Dir., GCI Ex. 2.0 Corr., 8:164-178. That is not disputed.

Proposed Decision and Alternatives. The Commission should approve figures for "Retirement Benefits, Net" of ($2,804,000) for North Shore and $68,887,000 for Peoples Gas. NS-PGL Ex. 40.1N, line 7; NS-PGL Ex. 40.1P, line 7. In other words, the Utilities should be allowed to recover the carrying costs of their prepaid pension expense, while at the same subtracting their OPEB liabilities. The Utilities respectfully submit that that would be the correct ruling given the evidence in the record and the applicable law.

In the alternative, as to North Shore, the Commission should (1) approve inclusion in North Shore's rate base of its recent pension contributions from internally generated sources, $4,001,111 and $11,139,238 in 2009 and 2010, respectively, Phillips Dir., NS Ex. 11.0, 7:142-146, less its OPEB liability; or (2) allow North Shore to recover as an income item the annual customer benefit (in terms of reduced pension expense in the utility's revenue requirement) of those two pension contributions, *i.e.,* $1,260,000 per year, *id*., while still including the OPEB liability in rate base. Finally, further in the alternative, the Commission should remove from rate base each utility's pension asset and its OPEB liability, *i.e.,* its Retirement Benefits, Net, to be fair and consistent.

The Evidence Establishes New Factual Points Supporting Inclusion of the Pension Assets in Rate Base. The reason the Commission in the 2007 and 2009 rate cases excluded from rate base Peoples Gas' pension asset and excluded the alternative of the Utilities' pension contributions, and the reason Staff and GCI in the instant cases propose the exclusion in rate base of the Utilities' pension assets and North Shore's pension contributions, is the theory that the pension assets and contributions were not funded by investors but instead by customers because the source of funds was funds from net cash from operating activities (in particular, the collection of customers' utility bills). *Peoples 2007*, p. 36; *Peoples 2009*, pp. 35-37; Ebrey Dir., Staff Ex. 3.0, 3:56 – 4:65, 4:69 – 7:46; Ebrey Reb., Staff Ex. 12.0, 3:52 – 4:71; *see also* Effron Dir., GCI Ex. 2.0 Corr., 8:180 – 10:212; Effron Reb., GCI Ex. 7.0, 8:179 – 9:182.[37]

The evidence in the instant cases, including new facts elicited by Staff at the evidentiary hearing, does not permit a finding that the pension assets and contributions were not funded by investors. In the 2007 and 2009 rate cases (and some other cases), and in Ms. Ebrey's reasoning,

[37] Mr. Effron simply applied *Peoples 2009* on this subject without discussing the rationale or presenting any other explicit support for the merits of his position. Please also note that the Utilities' appeals from the rulings on this subject in the 2007 and 2009 rate cases are pending.

the fact that a utility makes pension contributions and creates a pension asset using funds from net cash from operating activities has been taken to mean that none of those funds constitute capital of the utility. However, Utilities witness Ms. Phillips pointed out in her rebuttal testimony that "net cash from operating activities includes the portion of what customers pay on their bills for return of and on rate base as approved during the ratemaking process." Phillips Reb., NS-PGL Ex. 27.0, 9:184-186. In other words, part of what customers pay is the return of and on past capital investments of the utilities ("return of" being depreciation and amortization expense, and "return on" being the rate of return on rate base reflected as net income in the revenue requirement). The fact that the utility collects return of and on its capital investments does not mean that those collected funds then are not capital of the utility. Neither the facts nor logic supports that inference, which was refuted by Ms. Phillips. Moreover, the cross-examination of Utilities witness Ms. Gast by Staff showed another reason that inference is incorrect, *i.e.,* the portion of funds derived from collecting customers' utility bills that ends up as net income is retained earnings and thus is a part of equity. Gast Tr. 8/31/11, 399:5 – 400:12. These facts preclude any finding that the use of a portion of net cash from operating activities to make pension contributions and create a pension asset is not an expenditure of capital. These facts were not addressed in the 2007 and 2009 rate cases.

Ms. Ebrey's rebuttal did attempt to respond to Ms. Phillips' rebuttal, but, in essence, all that Ms. Ebrey did was claim that Ms. Phillips had not shown a change in facts since the 2007 and 2009 rate cases and state that the additional information that Ms. Phillips had supplied did not contradict North Shore's prior data request response about the source of funds for its 2009 and 2010 pension contributions. Ebrey Reb., Staff Ex. 12.0, 3:52 – 4:71. Neither point refutes or even undercuts what Ms. Phillips said. Moreover, Ms. Phillips' point about a portion of funds collected from customers being return of and on capital investments of the utility may not be a change in circumstances, but it is a new fact that was not in evidence and thus was not addressed by the Commission's Orders in the prior cases.

Mr. Effron agreed that, by definition, customers' payments of their utility bills cannot be direct contributions to a utility's pension trust. Effron Tr. 8/30/11, 205:11:14.

Further proof that it is erroneous to infer that use of funds from operations cannot be a use of capital is found in the facts that the pension assets are part of the Utilities' balance sheets and, with respect to defined benefit plans, which is what is involved here, that the Utilities own the assets, with the employees being the beneficiaries of the trust. Phillips Reb., NS-PGL Ex. 27.0, 9:192-195. These two facts were raised in the past cases, but they remain uncontested.

<u>Exclusion of the Pension Assets from Rate Base Would Be Contrary to Law</u>. The premise that customers, by paying utility bills, should be treated as if they had paid for the utility's assets, is wrong as a matter of law. Customers pay for service, not the property used to render it. *Bd. of Pub. Utility Commissioners, et al. v. New York Tel. Co.*, 271 U.S. 23 (1926).

Moreover, the Supreme Court of Illinois previously has rejected a claim that a utility's rate base should be reduced on the theory that part of it was the product of customer-supplied funds. In *Citizens Utilities,* the Commission in a rate case had made a $4,253,953 reduction in plant in a utility's rate base and reduced its depreciation expenses by $403,432, a total of $4,657,385, where the utility's existing rates had incorporated a level of income taxes that resulted in collecting through rates $4,657,385 more for income taxes than the utility actually had paid. The Commission, on appeal, sought to justify the reductions on the basis that the funds that paid for the plant were not investor-supplied but rather were customer-supplied, by virtue of the income tax over-recovery. *Citizens Utilities*, 124 Ill. 2d at 201-203, 204-205, 529 N.E.2d at

513, 514-515. The Supreme Court reversed, finding that the Commission's reductions constituted improper retroactive ratemaking. *Citizens Utilities*, 124 Ill. 2d at 203, 206-207, 210-211, 529 N.E.2d at 515-516, 517 (citing, *inter alia*, *Mandel Brothers, Inc. v. Chicago Tunnel Terminal Co.*, 2 Ill. 2d 205, 117 N.E.2d 774 (1954)). The Supreme Court stated in part:

> The Commission would derive from those cases the rule that a public utility's investors are not entitled to earn a return on sums that may be characterized as capital contributions by customers. We would note, however, that there was no contention made in either of the cited cases concerning retroactive ratemaking. The amounts at issue here were recovered by Citizens in past ratemaking orders as part of its income tax expense, and the validity of those orders cannot now be questioned.

Citizens Utilities, 124 Ill. 2d at 212, 529 N.E.2d at 518. Although the circumstances are not identical, here, too, Staff and GCI rely on the premise that customers' payments of bills under past rates means customers supplied the funds used to pay for the asset and, hence, the utility should earn no return on the asset. That is inconsistent with *Citizens Utilities*.

The decision in *Commonwealth Edison Co. v. Illinois Commerce Comm'n*, 398 Ill. App. 3d 510, 924 N.E.2d 1065 (2d Dist. 2009) ("*ComEd 2009*"), does not support denying the Utilities recovery of the carrying costs of their prepaid pension expense. In the rate case Order on Rehearing underlying the relevant portion of that Second District decision, the Commission had excluded Commonwealth Edison Company's ("ComEd") pension asset from rate base but allowed ComEd to recover a return at its cost of long-term debt on an $803 million contribution to the pension plan that was made in 2005 using funds supplied by ComEd's ultimate parent company. *ComEd 2009*, 398 Ill. App. 3d at 519-520, 924 N.E.2d at 1079. ComEd appealed, arguing that it should be allowed a return based on its overall cost of capital, not its cost of long-term debt, but the Second District affirmed, accepting the Commission's argument that ComEd has failed to carry its burden of proving that recovery of the $803 million contribution at ComEd's full cost of capital was reasonable or that there was not a less expensive alternative to funding the contribution than that full cost of capital. *ComEd 2009*, 398 Ill. App. 3d at 521-522, 924 N.E.2d at 1080. Thus, the question on appeal in *ComEd 2009* did not revolve around whether the funds used to contribute to the pension plan were investor-supplied, but around whether financing the contribution at the utility's full cost of capital, rather than its cost of long-term debt, was proven to be reasonable. The fact that the ComEd pension contribution was funded by its ultimate parent company does not warrant excluding the Utilities' pension assets from rate base. As discussed above, the facts of the instant cases do not permit the conclusion that the funding of the pension contributions and pension assets are customer-supplied.

Alternatively, North Shore Should Recover a Return on its 2009 and 2010 Pension Contributions. Although the facts and law support inclusion of the Utilities' pension assets in rate base (*i.e.*, recovery of carrying costs on their prepaid pension expense), in the alternative, as to North Shore, the utility should be allowed to include its 2009 and 2010 pension contributions in rate base or, alternatively, to recover the annual customer benefit of the contributions.

In addition to the facts referenced above, the Utilities showed that, with respect to North Shore's 2009 and 2010 pension contributions, the level of pension expense in the approved revenue requirement set in the 2009 rate cases was about \$2.9 million per year, much less than the \$4,001,111 and \$11,139,238 that North Shore contributed in 2009 and 2010, respectively. Phillips Reb., NS-PGL Ex. 27.0, 10:207-213.

The theory that customers somehow were funding the 2009 and 2010 North Shore pension contributions is fallacious for another reason. Neither of the Utilities has recovered its approved rate of return on common equity since 2003. Gast Dir., NS Ex. 2.0, 4:71; Gast Dir., PGL Ex. 2.0, 4:71. Thus, customers were not paying the utility's total costs of service, and it is not logical or fair to infer that they nonetheless were funding these pension contributions.

Finally, in ComEd's 2010 rate case, the Commission approved ComEd's recovery of costs relating to its 2009 pension contribution, which was shown to be funded using internally generated funds, although the recovery was set at the level of annual customer benefit, while the recovery of ComEd's 2005 pension contribution was continued based on a debt rate of return but reduced on an amortization theory. *ComEd 2010*, pp. 50-51, 98.

Accordingly, North Shore should recover the carrying costs of its 2009 and 2010 pension contributions by including them in rate base or, alternatively, should recover as an income item the annual customer benefit (in terms of reduced pension expense in the utility's revenue requirement) of those two pension contributions, *i.e.*, $1,260,000 per year. In either scenario, the OPEB liability still would be included in rate base.

<u>Alternatively, If the Pensions Assets and Contributions Are Excluded from Rate Base, then the OPEB Liabilities Also Should Be Excluded</u>. Finally, in the alternative, if the Utilities are not allowed to recover the carrying costs of their prepaid pension expense, or, in North Shore's case, even to earn a recovery as of its 2009 and 2010 pension contributions, then their OPEB liabilities should not be included in rate base. The pension assets / contributions and OPEB liabilities are similar in nature and should be treated on a consistent basis. Phillips Reb., NS-PGL Ex. 27.0, 2:40-42, 12:244-250. The Commission did not so rule in the 2007 and 2009 rate cases, but there is no valid factual or legal reason for disparate treatment of these items.

6. Accumulated Deferred Income Taxes

a. 50/50 Sharing Related to Tax Accounting Method Changes

The Utilities elected two tax accounting method changes: (1) a change in method of accounting related to the determination of unit of property used for repairs and retirements ("Repairs Change"); and (2) a non-automatic change to the capitalization of certain indirect and overhead costs ("Overhead Change"). Both of these tax accounting method changes are not final and are still subject to final rulings by the Internal Revenue Service ("IRS"). Because approval of these tax accounting method changes is far from certain and in the near term carries significantly greater risk than normal issues, the Utilities proposed that the benefits associated with the change be shared 50/50 with their customers. Hengtgen Dir., NS Ex. 7.0, 14:290 - 15:319; Hengtgen Dir., PGL Ex. 7.0, 16:344-17:377; Hengtgen Reb., NS-PGL Ex. 23.0 Corr., 12:260-14:290. Staff agrees with the Utilities' proposal. Kahle Reb., Staff Ex. 10.0 Corr., 23:504-24:527. However, GCI disagrees and proposes that 100% of the benefits be reflected in Accumulated Deferred Income Taxes (ADIT). The Commission should reject the GCI proposal.

(i) Repairs Change

GCI witness Mr. Morgan claims that sharing the benefit related to the Repairs Change is unnecessary because there simply is no significant IRS audit risk; it is subject to the same audit risk as everyday tax expenses. Morgan Dir., GCI Ex. 1.0 Corr., 13:1 – 14:13. Mr. Morgan errs.

As stated earlier, the Repairs Change relates to the determination of unit of property used for repairs and retirements. Stabile Dir., NS Ex. 10.0, 6:133-7:148; Stabile Dir., PGL Ex. 7.0, 6:133-7:148. As Utilities witness Mr. Stabile testifies, the change in tax accounting method is based on Internal Revenue Code ("IRC") Section 263 which provides: "No deduction shall be allowed for…Any amount paid out for new buildings or permanent improvements or betterments made to increase the value of any property or estate." *Id.* at 7:150-161; 7:150-161. The Proposed Treasury Regulations issued under this section in 2006 and in 2008 provide more detail and generally attempt to define a "unit of property." Stabile Reb., NS-PGL Ex. 26.0, 5:116-121.

Neither the 2006 proposed regulations nor the 2008 re-proposed regulations can be relied upon. Even if they could be relied upon, neither the 2006 nor the 2008 proposed regulations included a definition of a unit of property for network assets. As Mr. Stabile explains, because of the complexity of the issue, the Treasury Department and the IRS have encouraged individual industries to work separately within the confines of the Industry Issue Resolution ("IIR") program. The natural gas industry, through the American Gas Association and Interstate Natural Gas Association of America, has only in May 2011 initiated the IIR process for the industry. However, even if the IIR process is successful, no individual company's method will necessarily be the same as the IIR result or the final Treasury regulations issued under IRC Section 263, which would render IIR guidance null and void. Thus, until final regulations are issued or the IIR process is completed, the Utilities' tax accounting change methodology could vary significantly from the IIR resolution or ultimately the Treasury Department's final regulation; thus, there is significant risk. Stabile Reb., NS-PGL Ex. 26.0, 7:165-8:178. Even though more utilities have opted to make this election, it in no way lessens this risk – either a utility's methodology will comply with the IRS final regulations 100% or 0% or someplace in the middle.

Further, IRS audits involve more than simply finding math errors; they focus on issues. Stabile Reb., NS-PGL Ex. 26.0, 9:196-198. Even if the unit of property is reasonable and a company has applied that unit of property correctly, the IRS can still challenge a lot of judgment and factual information, such as whether amounts incurred that materially increase the value or substantially prolong the useful life of any unit of property, adapt the property for a new use, or as part of a plan of rehabilitation, modernization, or improvement to any unit of property have been improperly expensed as a repair. The audit risks in a post-change environment are going to be extremely significant until the IIR is concluded and final regulations issued. *Id.* at 9:198-206.

Finally, the Commission has addressed the risk associated with the Repairs Change. In ComEd's 2010 rate case, ICC Docket No. 10-0467, Mr. Effron made an accounting reserve and refunds proposal reflecting the Repairs Change in ADIT, even though ComEd had not yet made an election. *ComEd 2010*, p. 114. In its final Order, the Commission stated, with respect to ComEd's decision not to elect to make the Repairs Change:

> The Commission cannot conclude that ComEd's cautious behavior with the IRS, without more, is an act of imprudence. The Commission also cannot conclude that only ComEd's shareholder will benefit when and if ComEd elects to use this new tax procedure. As Staff points out, when the IRS issues guidelines on this new procedure, and when ComEd avails itself of this procedure, (providing it proves to be beneficial) ratepayers will benefit in the future. Additionally, ComEd used a historic test year. As Staff points out, any change regarding the IRS will not occur during the test year. The Commission therefore declines to adjust ComEd's rate base in the manner that Mr. Effron recommends.

ComEd 2010, p. 114. If the Commission recognized the risks to ComEd, and that the issue had not developed to a more certain level, it is clear the Utilities have risk with the method changes.

Therefore, the 50/50 sharing of the benefit associated with the Repairs Change is appropriate and Mr. Morgan's arguments are without merit.

(ii) <u>Overhead Change</u>

GCI witness Mr. Effron proposes to reflect 100% of the benefit associated with the Overhead Change in ADIT because he claims that the associated risk is not significant. Effron Dir., GCI Ex. 2.0, 11:241 – 13:274. Mr. Effron errs with respect to his proposal.

As Utilities witness Mr. Stabile explained, the Overhead Change has its genesis in the Simplified Service Cost Method ("SSCM") contained in the Treasury Regulations relating to IRC Section 263A, Uniform Capitalization Rules. In 2001, utilities began to elect the SSCM, which at the time could be made automatically. However, by 2003 as the number of utilities making the election increased, the IRS removed this election from the list of elections that could be made automatically and ultimately changed the applicable regulations disallowing the use of SSCM for any property with a life of more than three years. The implementation of the revised regulations disallowing use of the SSCM by utilities was abnormally harsh in that it required an immediate change in accounting in the middle of a tax year with no estimated payment relief. Stabile Reb., NS-PGL 26.0, 10:231-12:294.

Further, the IRS has designated this election a Tier 1 issue. The Large Business and International ("LB&I") Division of the IRS adopted a compliance issue tiering strategy in 2006 to ensure that high-risk compliance issues are properly addressed and treated consistently across the division for all LB&I taxpayers involved in the issue. This provides a consistent framework for identifying, prioritizing and addressing significant compliance risks in a nationally coordinated manner. There are three tiers, Tiers I, II, and III. Tier I is defined as follows:

> **"Tier I - High Strategic Importance**. Tier I issues are of high strategic importance to LB&I and have significant impact on one or more Industries. Tier I issues could include areas involving a large number of taxpayers, significant dollar risk, substantial compliance risk or high visibility, where there are established legal positions and/or LB&I direction.
>
> Tier I includes listed transactions as well as other "high-risk" transactions and issues that represent LB&I's highest compliance priorities."

Stabile Reb., NS-PGL 26.0, 10:231-12:294. Thus, Mr. Effron's claim that there is no substantial risk is baseless because by definition, as a Tier 1 issue, the Overhead Change involves "'high-risk' transactions and issues that represent LB&I's highest compliance priorities." Therefore, the 50/50 sharing of the benefit associated with the Overhead Change is appropriate and Mr. Effron's arguments are without merit.

(iii) Conclusion

To not recognize that a substantial risk exists with North Shore's and Peoples Gas' Repairs Change and Overhead Change would send a chilling effect to utilities in the future in making such elections before guidance from the Treasury Department and IRS is final. As Mr. Hengtgen explained, when a utility takes a tax deduction and reflects the impact of the deduction in its financial statements, the benefits of that deduction will inevitably be conveyed to customers through reduced rates. However, to the extent an election is subject to a final determination after audit or other Treasury action or law change that reverses a utility's position, it usually results in a utility returning the benefit without the ability to recover equivalent amounts from customers. Hengtgen Dir., NS Ex. 7.0, 14:304-15:319; Hengtgen Dir., PGL Ex. 7.0, 17:361-377. The Utilities, having made these elections, simply would like to share, 50/50, the risks as well as the benefits with the customers. Further, Staff agrees that the Utilities' sharing proposal is appropriate. As Staff witness Mr. Kahle states:

> The Commission should not discourage utilities from taking tax positions that have some risk associated with them when such positions are appropriate and could benefit ratepayers. …
>
> If the Commission adopted a policy of deducting 100% of the benefits of such tax positions from rate base, the Commission would essentially be assuming that utilities prevail in every instance. Given the doubtfulness of utilities prevailing in every such tax position, the Companies' 50/50 split proposal seems reasonable.

Kahle Reb., Staff Ex. 10.0 Corr., 24:508-527.

The GCI assertions against the Utilities' proposal are without merit as substantial risk exists with each election. The Commission should approve the Utilities' proposal.

b. <u>Derivative Adjustments from Contested Adjustments</u>

The Utilities' original Schedule B-9's show the projected balances of Accumulated Deferred Income Taxes at December 31, 2011 and December 31, 2012, and the average amounts for the test year. Hengtgen Dir., NS Ex. 7.0, 12:255-264; Hengtgen Dir., PGL Ex. 7.0, 15:323-328. Other than the contested issues discussed above and derivative adjustments from contested plant adjustments, these figures were not disputed by any party. The Utilities' final amounts are shown in NS-PGL Ex. 40.1N and 40.1P Corr.

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

The Utilities' original Schedule B-6's show the projected balances of Accumulated Depreciation at December 31, 2011, and December 31, 2012. Hengtgen Dir., NS Ex. 7.0, 10:201-219; PGL Ex. 7.0, 12:258–13:277. Other than derivative adjustments from contested plant adjustments, these figures were not disputed by any party. The Utilities' final amounts are shown in NS-PGL Ex. 40.1N and 40.1P Corr.

V. OPERATING EXPENSES

A. Overview/Summary/Totals

1 and 2. North Shore and Peoples Gas

North Shore in its surrebuttal testimony presented revised base rate operating expenses of $68,706,000, reflecting adjustments proposed by Staff and GCI with which the utility agreed or accepted in whole or in part and certain updates. NS-PGL Exs. 39.1N, 39.2N.

Peoples Gas in its surrebuttal testimony presented revised base rate operating expenses of $500,540,000, reflecting adjustments proposed by Staff and GCI with which the utility agreed or accepted in whole or in part and certain updates. NS-PGL Exs. 39.1P Corr., 39.2P Corr.

North Shore's and Peoples Gas' operating expenses are supported by extensive, detailed evidence, including the testimony of Sharon Moy (the test year, the overall revenue requirement, operating expenses, operating income, and the Gross Revenue Conversion Factor, and underlying calculations and support of various components of operating expenses);[38] Christine

[38] Moy Dir., NS Ex. 6.0, NS Ex. 6.1, NS Ex. 6.2 Public/Conf., PGL Ex. 6.0, PGL Ex. 6.1, PGL Ex. 6.2 Public/Conf.; Moy Reb. NS-PGL Ex. 22.0 2Corr., NS-PGL Ex. 22.1N 2 Corr., NS-PGL Ex. 22.2N 2 Corr., NS-PGL Ex. 22.3N 2Corr., NS-PGL Ex. 22.4N 2 Corr., NS-PGL Ex. 22.5N, NS-PGL Ex. 22.6N, NS-PGL Ex. 22.7N, NS-PGL Ex. 22.8N 2 Corr., NS-PGL Ex. 22.9N 2 Corr., NS-PGL Ex. 22.10N 2 Corr., NS-PGL Ex. 22.11N, NS-PGL Ex. 22.1P 2 Corr., NS-PGL Ex. 22.2P 2 Corr., NS-PGL Ex. 22.3P 2 Corr., NS-PGL Ex. 22.4P 2 Corr., NS-PGL Ex. 22.5P, NS-PGL Ex. 22.6P, NS-PGL Ex. 22.7P, NS-PGL Ex. 22.8P 2 Corr., NS-PGL Ex. 22.9P 2 Corr., NS-PGL Ex. 22.10P 2 Corr., NS-PGL Ex. 22.11P; Moy Surr., NS-PGL Ex. 39.0 Corr., NS-PGL Ex. 39.1N, NS-PGL Ex. 39.2N, NS-PGL Ex. 39.3N, NS-PGL Ex. 39.4N Public/Conf., NS-PGL Ex. 39.5N, NS-PGL Ex. 39.6N,

Gregor (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, depreciation and amortization expense, taxes other than income taxes expense, and intercompany costs);[39] Noreen Cleary (incentive compensation program expenses);[40] and Christine Phillips (employee benefits operating expenses, including pensions, OPEB, group insurance, and Integrys Business Support ("IBS")-billed benefits).[41]

B. Uncontested Issues

1. Physical Gas Losses

a. Modify Method of Accounting for Physical Gas Losses Associated with Manlove Field (PGL)

In rebuttal testimony, the Utilities accepted Staff's recommendation that Peoples Gas as of January 1, 2012, change its current method of accounting for physical gas losses to include its physical losses associated with Manlove in Account 823. Seagle Dir., Staff Ex. 8.0, 16:318 - 20:398; Puracchio Reb., NS-PGL Ex. 33.0 Rev., 6:122-7:147.

b. Amend Written Procedures for Treatment of Physical Losses of Gas from Underground Storage Fields (PGL)

The Utilities accepted Staff's recommendations that Peoples Gas (1) collaborate with Staff to develop written procedures for the treatment of physical losses of gas from underground storage fields that are agreeable to both Peoples Gas and Staff, (2) amend its existing written

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NS-PGL Ex. 39.7N, NS-PGL Ex. 39.8N, NS-PGL Ex. 39.1P Corr., NS-PGL Ex. 39.2P Corr., NS-PGL Ex. 39.3P, NS-PGL Ex. 39.4P Public/Conf., NS-PGL Ex. 39.5P Corr., NS-PGL Ex. 39.6P Corr., NS-PGL Ex. 39.7P Corr., NS-PGL Ex. 39.8P, NS-PGL Ex. 39.9 Public/Conf.

[39] Gregor Dir., NS Ex. 5.0, NS Ex. 5.1, PGL Ex. 5.0, PGL Ex. 5.1; Gregor Reb., NS-PGL Ex. 21.0 Corr., NS-PGL Ex. 21.1N, NS-PGL Ex. 21.1P, NS-PGL Ex. 21.2N, NS-PGL Ex. 21.2P, NS-PGL Ex. 21.3N, NS-PGL Ex. 21.3P, NS-PGL Ex. 21.4P; Gregor Surr., NS-PGL Ex. 38.0, NS-PGL Ex. 38.1P, NS-PGL Ex. 38.2, NS-PGL Ex. 28.3N, NS-PGL Ex. 38.3P, NS-PGL Ex. 38.4N, NS-PGL Ex. 38.4P.

[40] Cleary Dir., NS Ex. 9.0, NS Ex. 9.1 Public/Conf., PGL Ex. 9.0, PGL Ex. 9.1 Public/Conf.; Cleary Reb., NS-PGL Ex. 25.0; Cleary Surr., NS-PGL Ex. 43.0, NS-PGL Ex. 43.1, NS-PGL Ex. 43.2, NS-PGL Ex. 43.3 Affidavit.

[41] Phillips Dir., NS Ex. 11.0, NS Ex. 11.1, NS Ex. 11.2, PGL Ex. 11.0, PGL Ex. 11.1, PGL Ex. 11.2; Phillips Reb., NS-PGL Ex. 27.0, NS-PGL Ex. 27.1N, NS-PGL Ex. 27.1P, NS-PGL Ex. 27.2N, NS-PGL Ex. 27.2P, NS-PGL Ex. 27.3N, NS-PGL Ex. 27.3P, NS-PGL Ex. 27.4 Affidavit.

procedures to account for the use of Account 823 for physical losses, (3) allow Staff to verify the remaining procedures comply with Commission rules, and (4) file its amended procedures on e-docket in this docketed proceeding within six months of the date of the Final Order. Seagle Dir., Staff Ex. 8.0, 20:399-22:427; Puracchio Reb., NS-PGL Ex. 33.0 Rev., 7:148-154.

2. Distribution O&M

a. Expenses for locates, leak surveys, disconnects (O&M – PGL)

Peoples Gas accepted GCI's proposed adjustment decreasing distribution operation and maintenance ("O&M") expenses related to locates, leak surveys, and disconnections. Effron Dir., GCI Ex. 2.0 Corr., 18:393-19:420; Moy Reb., NS-PGL Ex. 22.0 2 Corr., 4:78-5:100.

b. Building Costs (PGL)

The Utilities accepted Staff's proposed adjustment decreasing O&M expenses related to Peoples Gas' leased property in Elwood, Illinois. Seagle Dir., Staff Ex. 8.0, 4:56-5:81. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 4:78-5:100.

3. Distribution O&M – Adjustment to Reflect Costs that Should Have Been Capitalized Instead of Expensed

Peoples Gas made uncontested corrections for distribution O&M expenses that should have been capitalized. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 20:450 – 21:454.

4. Distribution O&M - Inflation

GCI's rebuttal testimony accepted the Utilities' alternative adjustments for distribution O&M expenses inflation. Effron Reb., GCI Ex. 7.0, 11:234-12:250.

5. Distribution O&M - Building Lease (PGL)

The Utilities accepted Staff's lease adjustment. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 4:78 – 5:100.

6. Customer Service and Information

a. Advertising

Staff's rebuttal testimony withdrew the portion of Staff's advertising adjustments relating to customer satisfaction research. Ostrander Reb. Corr., Staff Ex 11.0, 3:54 – 4:69.

7. Administrative & General

a. Interest Expense on Budget Payment Plan

The Utilities accepted Staff's adjustment relating to interest expense on budget payment plans. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 4:78 – 5:100.

b. Interest Expense on Customer Deposits

The Utilities accepted Staff's adjustment relating to interest expense on customer deposits. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 4:78 – 5:100.

c. Lobbying

The Utilities accepted Staff's adjustment relating to lobbying expense. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 5:86.

d. Social and Service Club Dues

The Utilities accepted Staff's adjustment relating to social and service club dues. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 4:87.

e. Civic, Political, and Related

The Utilities at this time are not aware of an item to be discussed under this heading.

f. Charitable Contributions – Reclassification of 2012 Costs

The Utilities believe the portion of this sub-heading referring to charitable contributions is incorrect. *See* Sections V.B.6.a, *supra*, and V.B.9.b, *infra*. In their rebuttal testimony, the Utilities corrected the classification of certain 2012 test year data relating to Accounts 905 and

909, which does not relate to charitable contributions, and which has no net impact on their revenue requirements. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 19:408-415. This was not contested.

g. Inflation Factor Error-Miscellaneous Expense

The Utilities accepted Staff's adjustment correcting an inflation factor error relating to miscellaneous expense. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 4:78-5:100.

h. Employee Benefits – Adjustment to Test Year Pension and Benefits Expenses to Reflect Most Recent Actuarial Report

The Utilities updated pension and OPEB expenses to reflect the most recent actuarial report, which reduced these expenses by an aggregate $21,473,000. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 19:417 – 20:430. This was not contested.

i. Integrys Business Support Benefits Billed Expense

GCI withdrew its proposed adjustment related to IBS benefits expense. Effron Reb., GCI Ex. 7.0, 12:262-268.

j. Advertising

The Utilities accepted the portion of Staff's advertising adjustment not relating to customer satisfaction research. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 7:150-158.

8. Depreciation Expense on Utility Plant in Service – 2010 Actual

Staff accepted the Utilities' revisions to Staff's adjustments to depreciation expense for 2010 actual plant in service. Kahle Reb., Staff Ex. 10.0 Corr., 5:100 – 6:113.

9. Current Income Taxes

a. Bonus Depreciation, Illinois State Income Taxes and Tax Accounting Method Changes

Other than derivative adjustments from uncontested issues associated with bonus depreciation deduction for federal income taxes and the increase in Illinois State Taxes and the contested tax accounting method changes, these figures were not disputed by any party. The Utilities' final amounts are shown in NS-PGL Ex. 39.2N and 39.2P Corr.

b. Reclassification of Income Taxes on Charitable Contributions

The Utilities corrected the classification of income taxes for charitable contributions in the 2012 test year data, which has no net impact on their revenue requirements. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 18:401 – 19:407. This was not contested.

10. Invested Capital Tax (derivative adjustments)

The Utilities accepted Staff's adjustments to operating expenses related to Invested Capital Taxes. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 4:76-5-100.

11. Interest Synchronization (derivative adjustments)

There are no contested issues relating to income taxes as such. The only contested aspects here are the derivative impacts of contested adjustments that affect operating income.

12. Updated Inflation Rate

The Utilities accepted Staff's adjustments for inflation, subject to corrected income tax calculations. Moy Sur., NS-PGL Ex. 39.0 Corr., 1:12-15.

13. Rate 4 Revenues (NS)

The Utilities corrected North Shore's base rate revenues under Rate 4. Moy Reb., NS-PGL Ex. 22.0 2 Corr., 22:462-468. This was not contested.

C. <u>Contested Issues</u>

1. <u>Incentive Compensation</u> (Falls in Multiple Categories of O&M)

Staff and GCI propose to disallow significant portions of the Utilities' incentive compensation program costs in operating expenses and rate base. Their proposals are without merit. Due to the complexity of the proposed disallowances, the proposals will first be summarized,[42] and then the Utilities will discuss the flaws of the proposals with respect to each incentive compensation program and to the Utilities' compensation structure as a whole.

<u>Totals</u>. Staff and GCI combined propose to disallow the following incentive compensation program costs:

	Operating Expenses (Before Income Taxes) ("OE")	Rate Base ("RB")*	Rate Case Expenses
PGL	$7,267,000	$948,000	$54,000
NS	$1,272,000	$177,000	$39,000

Sources: Ebrey Reb., Staff Ex. 12.0 Corr., Sched. 12.2 P Corr., Sched. 12.2 N; Ostrander Supp. Reb., Staff Ex. 20.0 Corr., Sched. 20.1 P., p.3, Sched. 20.1 N., p.3.
*All rate base numbers in this discussion are net numbers, meaning they are Gross Plant minus associated Depreciation Reserve and associated ADIT.

<u>Peoples Gas Amounts Breakdown</u>. Staff's Peoples Gas proposals involve five "buckets" of disallowed costs plus certain derivative impacts.

[42] GCI's proposals are similar to a subset of Staff's proposed disallowances for the Executive Incentive Compensation Plan Costs and all of the Stock Plan Costs, based on identical reasoning. GCI has not proposed any disallowances to the Non-executive Incentive Compensation Plan Costs.

	OE Disallowances	RB Disallowances	Rate Case Expenses Disallowances
Non-executive Plan Costs	$2,196,000 out of $4,389,000; plus $16,000 of depreciation expense for RB disallowances	$491,000 out of $982,000	$54,000 of IBS goal sharing costs
Executive Plan Costs	$1,310,000 out of $1,364,000	N/A	N/A
Stock Plans Costs	$3,129,000 out of $3,129,000	N/A	N/A
Capitalized Costs Disallowed in 2007 Rate Cases	$5,000 of associated depreciation expense	$166,000	N/A
Capitalized Costs Disallowed in 2009 Rate Cases	$16,000	$483,000	N/A
[Derivative payroll taxes / accumulated depreciation and ADIT impacts]	$595,000	($150,000) (accum. deprec.) ($42,000) (ADIT)	N/A
Totals	$7,267,000	$948,000	$54,000

Sources: Ebrey Reb., Staff Ex. 12.0 Corr., Sched. 12.2 P Corr.; Ostrander Supp. Reb., Staff Ex. 20.0, Sched. 20.1 P., p.2.

North Shore Amounts Breakdown. Staff's North Shore proposals also involve four buckets of disallowed costs.

	OE Disallowances	RB Disallowances	Rate Case Expenses Disallowances
Non-executive Plan Costs	$416,000 out of $831,000; plus $2,000 of depreciation expense for RB disallowances	$86,000 out of $171,0000	$39,000 of IBS goal sharing costs
Executive Plan Costs	$202,000 out of $210,000	N/A	N/A
Stock Plans Costs	$544,000 out of $544,000	N/A	N/A
Capitalized Costs Disallowed In 2007 Rate Cases	$1,000	$27,000	N/A
Capitalized Costs Disallowed In 2009 Rate Cases	$2,000	$95,000	N/A
[Derivative payroll taxes / accumulated depreciation and ADIT impacts]	$105,000	($23,000) (accum. deprec.) ($8,000) (ADIT)	N/A
Totals	$1,272,000	$177,000	$39,000

Sources: Ebrey Reb., Staff Ex. 12.0 Corr., Sched. 12.2 N Corr.; Ostrander Reb., Staff Ex. 20.0., Sched. 20.1 P., p.2.

The remainder of this section will explain why Staff's and GCI's proposed disallowances to the various programs and the Utilities' incentive compensation as a whole should be rejected.

a. Non-Executive Incentive Compensation Plan

Staff (but not GCI) proposes to disallow 50% of the costs and rate base associated with the Utilities' Non-executive Incentive Compensation Plan. Staff's proposed disallowance is based on its position that the plan's cost-control metric requiring that certain levels of O&M expenses be met (upon which the plan places a 50% weighting) does not lead to customer benefits. Staff's proposal here is fatally flawed in that the Commission repeatedly has allowed recovery of incentive compensation costs related to metrics such as this one that are based on the control of O&M expenses.

Staff bases its proposed disallowance of costs related to the Non-executive Incentive Compensation Plan's O&M expense metric on three reasons: (1) it is a "financial" goal and thus non-recoverable; (2) the metric's target level for payout is based on the Utilities' 2012 test year budget; and (3) that the metric is calculated on a combined utility basis that includes amounts for Integrys affiliates operating outside of Illinois.[43] Ebrey Tr. 8/30/11, 231:7 – 234:5; Ebrey Dir., Staff Ex. 3.0 Corr., 12:247 – 13:265. None of these reasons provides a supportable basis for disallowing incentive compensation costs and each should be denied.

The O&M Expense Metric Is Not a "Financial" Goal. The Utilities' O&M expense metric at issue here is purely a cost-side item not at all based on revenues, for which payout will occur only if the Utilities keep the levels of their O&M costs at or below a certain level. Cleary Reb., NS-PGL Ex. 25.0, 10:204-209; Ebrey Tr. 8/30/11, 235:7-19. Thus, the Utilities' Non-executive Incentive Compensation Plan's O&M expense metric incentivizes employees to control or reduce expenses, which the Commission has consistently found to be a benefit to customers and, therefore, recoverable. As conceded by Staff witness Ms. Ebrey on cross-examination, the Commission specifically has approved recovery of costs related to metrics based on O&M expenses for providing benefits to customers. Ebrey Tr. 8/30/11, 235:20 – 236:11.

Indeed, a review of past Commission orders – upon which Staff purports to base its proposals (*id*. at 213:20 – 214:11) – reveals numerous instances of the Commission specifically ruling that a metric which incentivizes 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

[43] Staff witness Mr. Ostrander's proposed disallowances of rate case expenses for IBS "goal sharing" costs related to incentive compensation are based entirely on Staff witness Ms. Ebrey's proposal and grounds for disallowing 50% of the Non-executive Incentive Compensation Plan's costs related to its O&M expense control metric. Ostrander Reb., Staff Ex. 11.0 Corr., 6:121 – 7:135.

ratepayers." *Peoples 2007*, pp. 66-67. Similarly, in ComEd's 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"), pp. 95-96. The Commission reached similar conclusions in ComEd's 2007 rate case and other cases.[44] In ComEd's most recent rate case, the Commission again approved 100% recovery of an incentive compensation plan based, in part, on an O&M expense metric to which Staff had withdrawn all its proposed disallowances. *ComEd 2010*, pp. 60-65.

The Utilities' O&M expense metric, therefore, clearly is not a "financial goal" for which recovery is not allowed. Rather, it incentivizes the control and reduction of operating expenses, that, as the Commission previously has found, provides benefits for customers. Accordingly, the Commission should reject this basis for Staff's proposed adjustment.

<u>Using the 2012 Test Year Budget as a Target Level is Not a Basis for Disallowance</u>. Staff's second ground for proposing the disallowance of costs related to the Non-executive Incentive Compensation Plan's O&M expense control metric is that the target levels for payout under this metric are based upon the level of O&M expenses forecast in the Utilities' 2012 test year budget submitted for this rate case. Staff's position here is unfounded.

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[44] Other examples of where the Commission has ruled that expenses related to metrics which reduce operating costs, including O&M expenses, benefit customers and are recoverable include: *Commonwealth Edison Co.*, ICC Docket No. 07-0566 (Order Sept. 10, 2008) ("*ComEd 2007*"), pp. 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), p. 15; *Aqua Illinois, Inc.*, ICC Docket No. 04-0442 (Order April 20, 2005), pp. 21-22.

This basis for Staff's proposed disallowance ignores the fact that this determination is being made in the context of a general rate case using a future test year of 2012. By the very nature of a rate case using a future test year, a budgeted – *i.e.*, forecasted – target amount for O&M expenses must be used to set base rates because the future test-year has not yet occurred. Cleary Reb., NS-PGL Ex. 25.0, 12:239-243. If the Utilities meet or beat this budgeted level of O&M expense, this will, all else being equal, reduce the expenses to be recovered in future rates cases, which is a direct benefit to customers. *See ComEd 2005*, p. 96 ("Lowering O&M expenses, all else being equal, has the obvious effect of reducing the O&M expenses to be recovered in future rate cases.").

At the hearing, Staff witness Ms. Ebrey stated that her concern was "not just limited to the test year in this case," but that in going forward "budgeted numbers may be overestimated" in the future in order to meet this metric. Ebrey Tr. 8/30/11, 237:5-7. This is not a sound basis for a disallowance in a future test year rate case under the Commission's test year rules and principles. The recovery to be set in these rate cases is based only on the levels of O&M expense forecasted for the 2012 test year and meeting that level is the metric for incentive compensation payout, <u>not</u> some speculative budget to be set in the future. Furthermore, as both Utilities and Staff agree, the budgeted level of O&M expense at issue here for the 2012 test year has been subject to the full scrutiny of all the parties to this rate case proceeding, who could challenge that budgeted level if it were overestimated. Cleary Reb., NS-PGL Ex. 25, 12:252-255; Ebrey Tr. 8/30/11, 238:12-17. In light of such scrutiny, it is telling that neither Staff nor any other party has presented an iota of evidence that the Utilities' O&M budgets in this case were overestimated for purposes of meeting the incentive compensation metric. Moreover, Ms. Ebrey's speculation that "budget numbers may be overestimated" in the future in order to meet this metric is an improper basis for a Commission Order. *See, e.g., Ameropan Oil Corp. v. ICC*, 298 Ill. App. 3d 341, 348, 698 N.E.2d 582, 587 (1st Dist. 1998) ("speculation has no place in the ICC's decision"); *Allied Delivery System. Inc. v. Illinois Commerce Comm'n*, 93 Ill. App. 3d 656, 667, 417 N.E.2d 777, 785 (1st Dist. 1981) ("The speculation indulged in by the Commission is clearly an unsatisfactory and unacceptable basis for its decision.").

Further, Staff's "budget" argument also lacks support from the Commission's previous rulings on recovery of incentive compensation expenses. On cross-examination, Staff witness Ms. Ebrey admitted she was unaware of any Commission order in which a utility's incentive compensation costs were denied because a metric measured performance against a budget. Ebrey Tr. 8/30/11, 236:12-20, 239:10-15. That is because, to the contrary, the Commission has approved recovery of incentive compensation expenses in several cases where a metric was based on a utility's performance in meeting O&M expense targets measured by a budget. For example, in *Consumers Illinois Water Company*, ICC Docket No. 03-0403 (Order Apr. 13, 2004) ("*Consumers IWC*"), pp. 14-15, a case often-cited by the Commission as establishing the standard for recovery of incentive compensation costs, the Commission approved the recovery of Consumers Illinois Water Company's incentive compensation expenses which included a metric for "maintaining or reducing operating costs at or below *budgeted levels*." (Emphasis added). *Accord ComEd 2005*, p. 96[45]; *ComEd 2007,* pp. 54-55, 61 (approving recovery of costs for portions of incentive plan identical to those approved in *ComEd 2005*); *ComEd 2010, pp.* 61, 65 (approving recovery of costs for incentive plan similar to those approved in *ComEd 2007* except for removal of net income metric); *Aqua Illinois, Inc.*, ICC Docket No. 04-0442 (Order April 20,

[45] "While not expressly discussed by the Commission in its Order, the O&M metric it approved in this case was based on performance versus a budget, as explained in the testimony of ComEd's witness Richard F. Meischeid II (ComEd Ex. 12 at 13:284-287), available on the Commission's e-Docket system for ICC Docket No. 05-0597." Cleary Reb., NS-PGL Ex. 25.0, p. 12, fn. 4.

2005), pp. 21-22 (approving recovery of costs for incentive plan similar to the plan approved in *Consumers IWC*).

Staff attempts to rely on the Commission's recent Order denying ComEd's request for approval of an alternative rate regulation plan pursuant to Section 9-244 of the Public Utilities Act, 220 ILCS 5/9-244, *In re Commonwealth Edison Co.*, ICC Docket No. 10-0527 (Order May 24, 2011) ("*ComEd Alt. Reg.*"). *See* Ebrey Dir., Staff Ex. 3.0 Corr., 13:266 – 14:297; Ebrey Tr. 8/30/11, 237:11-14. The *ComEd Alt. Reg.* Order, however, is inapposite to the question of whether incentive compensation expenses are recoverable in a general rate case. As discussed above, the "budget" amounts at issue here are the 2012 test year numbers themselves, which have been subject to full scrutiny as part of this rate case and will be used by the Commission as the basis for setting the Utilities' base rates going forward. Cleary Reb., NS-PGL Ex. 25.0, 12:252-255. By contrast, the budget targets for the projects at issue in the ComEd alternative regulation proceeding were not being reviewed and vetted as part of a complete base rate case, and thus, the Commission was concerned that under those circumstances there was not "sufficient transparency to determine if the proposed budgets are reasonable." *ComEd Alt. Reg.*, p. 19. This concern about insufficient "transparency" does not exist here where the budgeted amount at issue is for O&M expenses that are normally and traditionally part of a utility's expenses reviewed in the course of a rate case and that amount is being subjected to the full scrutiny of a base rate proceeding. Cleary Reb., NS-PGL Ex. 25.0, 13:260-263.

<u>Inclusion of Affiliate Performance in the O&M Expense Metric Does Not Support Staff's Proposed Adjustment</u>. Staff's third ground for its proposed disallowance (which supports only 44% of the disallowance as to Peoples Gas and 46% as to North Shore) is that a portion of the O&M expense metric is calculated on a combined utility basis that includes amounts for the

affiliates operating outside of Illinois. Ebrey Dir., Staff Ex. 3.0 Corr., 13:259-265. This also is an inappropriate ground for Staff's proposed disallowance. The uncontradicted evidence, provided by the testimony of Utilities witness Ms. Cleary, is that this structure for the O&M expense metric reflects the Utilities' and Integrys' team-based philosophy that encourages Integrys' non-Illinois affiliates to share best practices with the Utilities. Cleary Reb., NS-PGL Ex. 25.0, 5:109 – 6:112, 13:269-271. This creates benefits for Illinois customers, and because the Utilities share that corporate level of staff support, their share of the expense for that support should be recoverable. *Id*. at 6:111-114. The evidence demonstrated that Integrys' sharing best practices at a corporate level allows all of its affiliates, including the Utilities, to have access to high-quality, but expensive, resources and experts that the Utilities on their own would find it difficult to afford. *Id*. at 6:115-118, 13:272-276. Ms. Cleary testified to specific examples of such programs providing direct benefits to Illinois customers in terms of increased safety and improved customer satisfaction. *Id*. at 6:119 – 7:134; Cleary Sur., NS-PGL Ex. 43.0, 4:87 – 5:96. The uncontradicted evidence in the record is that this allows Peoples Gas and North Shore to lower their O&M expenses, which results in direct benefits to Illinois customers. Cleary Reb., NS-PGL Ex. 25.0, 13:276-277.

This third ground for a portion of Staff's proposed adjustment is unfounded and there should be no disallowance for any of the Non-executive Incentive Compensation Plan's costs. However, both the Utilities and Staff agree that if this third ground is the only basis upon which the Commission believes that costs related to the O&M expense metric should be disallowed, then the amount of that disallowance should be adjusted to reflect only the portion of those costs allocated to Integrys' non-Illinois affiliates. Cleary Reb., NS-PGL Ex. 25.0, 13:278 – 14:297; Cleary Sur., NS-PGL Ex. 43.0, 8:172 – 9:196; Ebrey Tr. 8/30/11, 234:6 – 235:2. Staff and

Utilities agree that under that scenario, the apportionment of the costs for disallowance should be the same as Staff proposed for portions of the Executive Incentive Compensation Plan: 44% and 46% of the costs and rate base associated with the O&M expense metric for Peoples Gas and North Shore, respectively. Cleary Reb., NS-PGL Ex. 25.0, 14:291-297; Cleary Sur., NS-PGL Ex. 43.0, 9:180-185; Ebrey Tr. 8/30/11, 235:3-7.

b. Executive Incentive Compensation Plan

Both Staff and GCI seek disallowances for portions of the Utilities' Executive Incentive Compensation Plan. The proposals can be divided into those addressing the Executive Incentive Plan's diluted Earnings Per Share ("EPS") metric and those related to the plan's operational metrics. Both sets of proposed adjustments lack merit for the following reasons.

EPS Metric. Both Staff and GCI seek the disallowance of the 70% of the Executive Incentive Compensation Plan's costs that are based on an EPS metric, alleging that this is a financial metric that does not incentivize customer benefits.[46] The actual record evidence, however, demonstrates that the EPS metric can and does incentivize the Utilities' executives to reduce operating expenses, which, as discussed above, the Commission has held to be of benefit to customers. As explained by Utilities witness Ms. Cleary, the EPS metric is derived from net income, which is dependent on both revenues and costs, so that executive employees have a significant incentive to reduce costs, which will result in a higher EPS. Cleary Reb., NS-PGL Ex. 25.0, 5:97-100; Cleary Sur., NS-PGL Ex. 43.0, 3:58-62. Indeed, both Staff and GCI witnesses agreed that, all else being equal, EPS will increase if a utility reduces its operating expenses. Ebrey Tr. 8/30/11, 226:7-10; Effron Tr. 8/30/11, 202:5-10. Thus, customers can benefit from the Utilities' EPS increasing. Effron Tr. 8/30/11, 202:11-20.

[46] Ebrey Dir., Staff Ex. 3.0 Corr., 9:186 – 191; Ebrey Reb., Staff Ex. 12.0 Corr., 6:107 – 7:116; Effron Dir., GCI Ex. 2.0, 16:359-361; Effron Reb., GCI Ex. 7.0, 10:223 – 11:231.

Moreover, the Utilities provided a concrete example of how the EPS metric has worked to incentivize their executives to reduce expenses for purposes of increasing EPS, thereby benefiting customers. Ms. Cleary testified that the Utilities' top executives agreed to forego a general wage increase in 2009 in order to reduce costs and improve EPS, and that this one example alone resulted in a benefit to customers in the amount of $127,082. Cleary Reb., NS-PGL Ex. 25.0, 5:100-104; Cleary Sur., NS-PGL Ex. 43.0, 3:62 – 4:72. The uncontradicted evidence, therefore, is that the Utilities' EPS metric *does* benefit customers and thus, under the customer benefit standard urged by Staff and GCI, the costs associated with this metric should be recoverable. Accordingly, Staff's and GCI's proposed disallowances should be rejected.

<u>Non-financial Operational Metrics</u>. Staff (but not GCI) seeks additional adjustments to the remaining 30% of the costs related to the Executive Incentive Compensation Plan's three non-financial operational metrics concerning employee safety, customer satisfaction and environmental impact reduction. Staff's proposed adjustment is based on the fact that these operational metrics consider the achievements of all the Integrys utilities, including non-Illinois affiliates of the Utilities. Ebrey Dir., Staff Ex. 3.0 Corr., 10:201 – 11:207. Staff thus seeks disallowance of the portion of those costs allocated to the Utilities' non-Illinois affiliates (44% for Peoples Gas and 46% for North Shore). *Id*. at 10:201-204 and Scheds. 3.2 P and 3.2 N. This proposed adjustment is unfounded and not supported by the record evidence.

As discussed above, Integrys and the Utilities operate on and share a team-based philosophy, whereby Integrys, at the corporate level, operates programs that allow each of its affiliates, including Peoples Gas and North Shore, access to experts and industry-wide best practices programs that each affiliate unlikely would be able to afford on its own. Cleary Reb., NS-PGL Ex. 25.0, 5:109 – 6:118. In her testimony, Ms. Cleary gave specific examples of such programs related to each of the Executive Incentive Compensation Plan's operational metrics and explained how they directly benefit customers *in Illinois*:

- A benchmark safety program giving Peoples Gas and North Shore access to a specialized team of experts that has led to Peoples Gas and North Shore reducing their OSHA recordable rates from 10.43 to 3.34 and 11.31 to 2.59 between 2010 and the first quarter of 2011, respectively, *Id*. at 6:119-132; Cleary Sur., NS-PGL Ex. 43.0, 4:87 – 5:98;
- Access to J.D. Powers methodologies for improving customer service, Cleary Reb., NS-PGL Ex. 25.0, 7:133-134; Cleary Sur., NS-PGL Ex. 43.0, 5:99-100; and
- Access to a team of environmental experts for Peoples Gas and North Shore to consult on reducing greenhouse gas emissions. Cleary Reb., NS-PGL Ex. 25.0, 7:134-136; Cleary Sur., NS-PGL Ex. 43.0, 5:100-102.

Ms. Cleary's uncontradicted testimony is that these programs allow Peoples Gas and North Shore to provide benefits to their customers in Illinois. Cleary Reb., NS-PGL Ex. 25.0, 7:136-141; Cleary Sur., NS-PGL Ex. 43.0, 5:104-107. Accordingly, the costs for the incentive compensation metrics related to these programs that incentivize the Utilities' executives to generate those benefits for Illinois customers should be recoverable.

Staff also seeks a further 50% reduction of the costs related to these operational metrics of the Executive Incentive Compensation Plan because the plan provides that payouts for these metrics will be reduced by 50% if the EPS threshold is not met, so that the accuracy of the forecast is called into question. Ebrey Dir., Staff Ex. 3.0 Corr., 11:205-211. The uncontradicted evidence presented by the Utilities, however, is that it is reasonable to expect the EPS threshold to be met because since its formation in 2007, Integrys has consistently met its EPS targets disclosed to and relied upon by the financial community. Cleary Reb., NS-PGL Ex. 25.0, 8:162-165. Furthermore, this proposed adjustment should be rejected for the same reasons discussed above with respect to the recoverability of costs relating to the EPS metric.

All of Staff's and GCI's proposed disallowances with respect to the Executive Incentive Compensation Plan, therefore, are flawed and the Utilities should be allowed to recover all of their expenses related to this plan.

c. Omnibus Incentive Compensation Plan (Stock Plans)

Both Staff and GCI propose disallowing all of the Utilities' costs for their incentive stock plans, collectively known as the Omnibus Incentive Compensation Plan, for allegedly being based on financial measures that primarily benefit shareholders and not customers. Ebrey Dir., Staff Ex. 3.0 Corr., 15:308 – 16:331; Effron Dir., GCI Ex. 2.0, 16:357-364. This argument ignores, however, the uncontradicted testimony of Utilities' witness Ms. Cleary that, absent the incentive stock plans, the Utilities' compensation package could not be competitive with the other energy and non-energy companies with which they compete for employees that offer compensation packages which include stock plans in addition to base pay and incentive pay. Cleary Reb., NS-PGL Ex. 25.0, 16:354 – 17:357. Moreover, Staff's and GCI's position also ignores the uncontradicted evidence presented by the Utilities that the incentive stock plans benefit customers by helping the Utilities maintain a steady and experienced executive team that leads to the Utilities' efficient and successful operation. *Id*. at 17:357-360. This inures to the benefit of customers. Thus, the costs of the incentive stock programs are reasonable and prudent costs and the Commission should deny this proposed disallowance.

d. The Utilities' Incentive Compensation Costs on the Whole Are Recoverable as Prudent and Reasonable Operating Costs

Furthermore, in addition to the individual reasons provided above demonstrating that each of the incentive compensation programs meet the customer benefits standard argued for by Staff and GCI, the Utilities' incentive compensation costs as a whole are recoverable because they are reasonable and prudent operating costs. No witness challenged the testimony of the Utilities' witness, Noreen Cleary, regarding the prudence and reasonableness of each of the incentive compensation plans at issue.[47] Ms. Cleary's uncontradicted testimony established, among other things, that: (1) the Utilities design their total cash compensation packages (base pay plus target incentive pay) at market median based on other energy service companies based on data from Towers Watson, a nationally recognized compensation and benefits firm; (2) the Utilities design their total compensation programs, including their incentive compensation programs, in order to attract and retain a sufficient, qualified, and motivated work force; and (3) attracting and retaining such a work force benefits customers by making sure there are enough employees to perform needed work, by maintaining and improving the quality of work, and reducing the expenses associated with recruiting and retaining new employees.[48]

Even in today's economic environment, the Utilities' approach is prudent and reasonable, and the alternative of moving more compensation to base pay would put them at a disadvantage in the labor market. Cleary Dir., PGL Ex. 9.0, 3:66 – 4:74 and NS Ex. 9.0, 3:66 – 4:74.

Ms. Cleary also testified, as to the stock plans, that they are an important part of the overall total compensation package, again are designed to help attract and retain a qualified and

[47] Neither the Staff witness nor the GCI witness is an expert on human resources. *See* Ebrey Tr. 8/30/2011, 212:16-21; Effron Tr. 8/30/2011, 189:9-14.

[48] *E.g.*, Cleary Dir., PGL Ex. 9.0, 2:44 - 4:93; Cleary Dir., NS Ex. 9.0, 2:44 – 4:93; Cleary Reb., NS-PGL Ex. 25.0, 1:20 – 2:23, 4:71-82, 17:364 – 18:388. (Ms. Cleary adopted the pre-filed Direct testimony of Utilities witness James Hoover, so it is referred as "Cleary Dir.".)

motivated work force, and that without them the Utilities' compensation packages would be less competitive because their labor market competitors, both energy and non-energy companies, offer compensation packages that include base pay, incentive pay, and stock plans.[49]

The Commission cannot ignore the uncontradicted evidence regarding the prudence and reasonableness of the incentive compensation costs or the benefits received by customers. The Commission must apply Illinois law governing uncontradicted evidence. "Where the testimony of a witness is neither contradicted, either by positive testimony or by circumstances, nor inherently improbable, and the witness has not been impeached, that testimony cannot be disregarded by the trier of fact." *Bazydlo v. Volant*, 164 Ill. 2d 207, 215, 647 N.E.2d 273, 277 (1995).[50]

The cross-examination of Staff's witness showed, moreover, that its application of the Commission's past standards is illogical and unreasonable. Even when the total compensation paid to employees is prudent and reasonable, Staff's application of the Commission's past decisions would result in arbitrary and illogical selective disallowances depending on the metrics of the incentive portions of the compensation. Ebrey Tr. 8/30/2011, 213:15 – 225:3. That also makes no sense because Staff's witness admitted that the fact that a metric benefits shareholders does not necessarily mean that it is contrary to the interests of customers, and that if a metric benefits both shareholders and customers that does not mean shareholders should bear all of the costs associated with the metric. Ebrey Tr. 8/30/2011, 226:11 – 227:2; Effron Tr. 8/30/2011, 199:16 – 200:9, 202:5-20.

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[49] Cleary Reb., NS-PGL Ex. 23.0, 16:345-360; Cleary Sur., NS-PGL Ex. 43.0, 10:214-219. As to the fourth and fifth cost "buckets", Mr. Hengtgen made the point that the capitalized amounts disallowed under the Orders in the 2007 and 2009 rate cases are on appeal. Hengtgen Reb., NS-PGL Ex. 23.0, 22:470-481.

[50] *See also ComEd*, 322 Ill. App. 3d at 849, 751 N.E.2d at 199; *Thigpen v. Retirement Bd. of Fireman's Annuity and Benefit Fund of Chicago*, 317 Ill. App. 3d 1010, 1021, 741 N.E.2d 276, 284 (1st Dist. 2000); *Trahraeg Holding Corp. v. Property Tax Appeal Bd.*, 204 Ill. App. 3d 41, 44, 561 N.E.2d 1298, 1300 (2d Dist. 1990).

The principle that a utility is entitled to recover its prudent and reasonable costs of service is well-established. *See*, *e.g.*, *CUB*, 166 Ill. 2d at 121, 651 N.E.2d at 1095. It is settled law, moreover, that employee salaries are operating expenses and, as such, are recoverable in full so long as they are prudent and reasonable. *See, e.g., Villages of Milford v. Illinois Commerce Comm'n*, 20 Ill. 2d 556, 565, 170 N.E.2d 576, 581 (1960) ("*Milford*"). Under these principles, therefore, the Commission should reject Staff's and GCI's proposed disallowances because it is undisputed that the incentive compensation costs at issue are prudent and reasonable.

The present case also is distinguishable from *Commonwealth Edison Co. v. Illinois Commerce Comm'n*, 398 Ill. App. 3d 510, 924 N.E.2d 1065 (2d Dist. 2009) ("*ComEd 2009*"), in which the Illinois Appellate Court for the Second Judicial District affirmed the Commission's decision in the 2005 ComEd rate case to disallow half of the utility's incentive compensation costs (*ComEd 2005*, pp. 95-97). First, the court's reliance in *ComEd 2009* on *DuPage Util. Co. v. Illinois Commerce Comm'n*, 47 Ill. 2d 550, 560, 267 N.E.2d 662, 667 (1971) ("*DuPage*"), which distinguished *Milford*, is inapplicable here. *ComEd 2009*, 398 Ill. App. 3d at 517, 924 N.E.2d at 1077. That is because in *DuPage*, the Court, distinguished *Milford*, basing its decision on evidentiary supported findings that the salaries of three officers of a company serving 840 customers were excessive rather than reasonable, including evidence that the officers only worked part-time and maintained only a minimal contact with the utility's day to day operations, and that their salaries were disproportionately high compared to comparable utilities. *DuPage*, 47 Ill. 2d at 560, 276 N.E.2d at 667. There is no claim, much less any evidence, of excessive compensation on those or any other grounds in the instant cases. The only evidence is to the contrary. Second, the Second District also discussed some of ComEd's evidence of customer benefits, finding that "this evidence certainly does provide support for ComEd's position, it does not compel the conclusion that ComEd seeks." *ComEd 2009*, 389 Ill. App. 3d at 518, 924 N.E.2d at 1078. Here, the evidence does compel the conclusion that customers benefit from the Utilities' incentive compensation plans.

Finally, and critically, the Second District relied on the fact that the Commission had approved half of ComEd's incentive compensation costs.

> If we were deciding this issue in a vacuum, we might agree with ComEd. However, in this case, three other performance-based components of the incentive plan existed. Thus, the Commission could have reasonably concluded that the earnings-per-share portion of the plan provided only a tangential benefit to ratepayers. Indeed, the Commission characterized this portion of the incentive plan as "generic and broad" in contrast to the other three more specific components. Moreover, precedent exists for apportioning employee compensation costs between equity holders and ratepayers where an employee's duties only partially benefit ratepayers. See *Candlewick Lake Utilities Co.* [*v. Illinois Commerce Comm'n*], 122 Ill. App. 3d [219] at 226 [(2d Dist. 1983)]. Meischeid's testimony that such plans benefit everyone necessarily entails the proposition that they provide only some benefit to customers and thus provides an adequate basis for the Commission's decision to apportion these costs. Moreover, the notion that an earnings-per-share-based employee incentive plan provides benefits to shareholders is hardly a controversial proposition.

ComEd 2009, 398 Ill. App. 3d at 519, 924 N.E.2d at 1078.[51] Here, however, unlike the 2005 ComEd rate case, the numbers set forth above show that Staff proposes to disallow a significant portion of the Utilities' incentive compensation costs, even though they include "operational" metrics, such as metrics tied to controlling O&M costs, system reliability and customer satisfaction. Thus, the "tangential benefit" and "apportionment" reasoning of the Second District does not apply here.

The Commission, therefore, should reject Staff's and GCI's proposed disallowances. The costs at issue are prudent and reasonable, and they benefit customers in multiple respects.

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[51] In *Candlewick*, which involved the salary of one company officer, "the Commission noted that it based its decision on the unusual circumstances of an absent non-resident president, the past financial difficulties of the utility including a bankruptcy reorganization, the presence of various management and clerical employees to run the day-to-day operations of the utility, and the fact that the president's duties are undocumented." *Candlewick*, 122 Ill. App. 3d at 226, 460 N.E.2d at 1195. Again, the instant cases do not involve any claim, much less evidence, of any such circumstances.

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

Staff's two-step proposal to decrease Peoples Gas' and North Shore's non-union base wages lacks merit and should not be adopted.

In 2011, the Utilities increased their non-union base wages by a total of 3.9%, which consists of a 3% general wage increase (effective February 2011), with two additional pools of funds equal to .3% and .6% of the Utilities' 2010 base wages to provide merit increases for high-performing employees and pay salary increases corresponding to employee promotions, respectively. Cleary Reb., NS-PGL Ex. 25.0, 19:412-418; Cleary Sur., NS-PGL Ex. 43.0, 11:225-233. For the 2012 test year, the Utilities forecast a similar increase from its 2011 level of non-union base wages. Cleary Reb., NS-PGL Ex. 25.0, 21:452-453; Cleary Sur., NS-PGL Ex. 43.0, 12:247-252.

Staff's first step is proposing to decrease the Utilities' 2011 non-union base wage level through escalating the Utilities' 2010 non-union base wage levels by only 3.0%, effectively removing the .3% and .6% discrete pools of funds used to provide merit increases and salary increases corresponding to promotions, respectively. The basis for Staff's proposal to remove these increases is that while the general wage increase of 3.0% was supported by the most current World at Work Survey, only the "highest performers" could expect as high as a 4.0% increase. Ebrey Reb., Staff Ex. 12.0 Corr., 14:247 – 15:264.

Staff's reasoning for proposing the removal of the .3% and .6% discrete pools of funds from the amount of forecasted level of wages is not supported. This reasoning ignores the fact that these funds *are* being used to provide raises to the Utilities' highest performers – those deserving of merit-based wage increases and/or promotions. Cleary Sur., NS-PGL Ex. 43.0, 11:234-239. The pool of funds that, in total, equals .3% of the previous year's level of wages is used to give discrete performance raises to certain top-performing non-union employees with commendable or exemplary performance. Cleary Reb., NS-PGL Ex. 25.0, 20:440-445. This was not, as assumed by Staff, an across the board increase to all employees elevating all of them to a “top-performer” status; rather, only certain top-performers received merit raises which, in the aggregate, total .3% of the overall wage base.

With respect to the pool of funds equal to .6% of the overall wage base, Staff’s analysis of this amount based upon the World at Work Surveys or consumer inflation predictions is inapposite. That is because this amount does not represent general inflationary wage increases, but rather, salary increases that correspond to the promotions of certain employees, *i.e.,* changes in certain employees’ relative positions within the Utilities based on the going market based rate of pay for their new elevated positions. Cleary Sur., NS-PGL Ex. 43.0, 11:239 – 12:246. These are promotions that had been put on hold since a freeze on promotions was put in place in 2008, and the Utilities would be in danger of losing these trained and experienced employees unless they are recognized for the promotions they are due. Cleary Reb., NS-PGL Ex. 25.0, 21:446-450.

Staff’s second step is to then propose that the increase in non-union base wages forecast from 2011 to the 2012 test year be reduced from 3.9% to 2.30%. Ebrey Reb., Staff Ex. 12.0 Corr., 17:299-304. Staff achieves this decrease by (a) removing the .3% and .6% discrete pools of funds used to provide merit increases and salary increases corresponding to promotions, respectively, and (b) adjusting the general wage increase downward from 3.0% to 2.30% based upon a level of the Consumer Price Index (“CPI”) forecast for the 2011-2015 period. *Id.* at 15:265 – 17:298. Staff’s proposed removal of the .3% and .6% discrete pools of funds for the 2012 test year should be denied for the same reasons explained above for 2011. The remainder of this section will address why Staff's proposed reduction in the level of general wage increases based on a forecast of CPI lacks merit.

In her testimony, Staff witness Ms. Ebrey admits that projected total salary budget increase projected by the 2011-2012 World at Work Survey for 2012 is 2.9%. *Id*. at 14:253-254. The World at Work Salary Budget Survey is a well-known compensation tool that is based on information submitted by corporations in all industries for the specific purpose of assisting in corporate salary budget planning. Cleary Reb., NS-PGL Ex. 25.0, 19:405-408. The results of this survey are tied directly to the market and support the Utilities' compensation philosophy of paying at the market median. *Id*. at 19:408-411. Moreover, it is forward looking and specifically designed to address the question of what level of general wage increases are forecast for 2012, the test year in this case. The 2.9% level projected for 2012 by the World at Work Survey is right in line with and supports the Utilities projected 3.0% general increase in the level of non-union wage base in the 2012 test year.

In contrast, the CPI is not a measure designed to calculate changes in wages, but rather, an economic indicator calculated by the Bureau of Labor Statistics to show a change over time in the prices paid by consumers for a market basket of goods and services. *Id*. at 19:421-424. As the Utilities' witness Ms. Cleary testified: "It is a measure that reflects spending patterns of consumers, not the wage setting decisions of employers." *Id*. at 19:424 – 20:425. Ms. Cleary further testified that the Bureau of Labor Statistics calculates and publishes a completely different measure specifically designed to measure changes in wages and salaries by industry – the Employment Cost Index – which has shown that wages in the utility industry have been increasing at a faster pace than overall wages generally. *Id*. at 20:428-435; Cleary Sur., NS-PGL Ex. 43.0, 12:255 – 13:263 and fn. 4.

Furthermore, Staff's attempt to base its reliance on the CPI forecast rather than the World at Work Survey for 2012 or the Employment Cost Index on the fact that the CPI forecast for 2011-2015 would be "more in line with the period the rates set in this proceeding will be in effect"[52] is improper for two reasons. First, this basis includes a speculative assumption regarding how long the rates set in these cases will remain in effect. Cleary Sur., NS-PGL Ex. 43.0, 13:271-276. Second, this would look outside of the 12-month period being examined for the purposes of setting the Utilities' base rates in this proceeding, thereby violating the Commission's test year rules and policies. *Id*. at 13:275-276. This attempt to look beyond the 2012 test year to justify Staff's proposed reduction in base wages is thus improper and should be rejected.

Accordingly, Staff's two-step proposal for reductions in the Utilities' non-union base wages is neither justified nor supported by the record evidence, and should be rejected.

3. Headcounts (Falls in Multiple Categories of O&M)

GCI witness Mr. Effron proposes a disallowance based on his conclusion that Peoples Gas will not have as many employees as forecasted. Mr. Effron bases his conclusion on the fact that Peoples Gas has forecasted 1,120 employees for the 2012 test year and as of early 2011 Peoples Gas actual number of employees was 1,089. Effron Dir., GCI Ex. 2.0 Corr., 13:280-286; Effron Reb., GCI Ex. 7.0, 10:211-222. Mr. Effron's adjustment should be rejected.

Mr. Effron's bare opinion, without more, cannot overcome Peoples Gas' testimony indicating it would be hiring more employees. Utilities witness Mr. Doerk testified that Peoples Gas had specific plans to bring on new employees. Doerk Reb., NS-PGL Ex. 24.0, 5:94 - 6:99. Peoples Gas is currently filling 30 temporary Operations Apprentice positions to complete an

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[52] Ebrey Reb., Staff Ex. 12.0 Corr., 16:275-281.

ever expanding workload. Even though these hires are intended to be on the payroll for 18 months, alternative resources will be deployed to fulfill the compliance inspections, including prospective Utility Workers to be hired from a proposed company designated trade school. *Id*. By the time of surrebuttal testimony, 20 of these positions had been filled and the remaining 10 positions were to be filled within weeks. Doerk Sur., NS-PGL 41.0, 2:24-33. These employees being hired are necessary for the direct execution of compliance work. *Id.* Furthermore, over 2011 and 2012, due to normal attrition and increased resources required for AMRP, Peoples Gas will be continually hiring more people to maintain the budgeted head count. *Id.* Thus, Peoples Gas' forecast is realistic and Mr. Effron's proposed decrease should be rejected.

4. <u>Self-Constructed Property</u>

GCI proposes to remove $1,722,000 of costs of self-constructed property from Peoples Gas' operating expenses on the ground that they should have been capitalized and treated as an addition to plant. Effron Dir., GCI Ex. 2.0 Corr., 27:595-600; Effron Reb., GCI Ex. 7.0, 13:285-287. Yet, GCI inconsistently and unfairly did not propose to add these costs to Peoples Gas' rate base. GCI cannot have it both ways. The prudence and reasonableness of these costs is not challenged. They belong either in operating expenses or rate base. Gregor Sur., NS-PGL Ex. 38.0, 5:87-89.

GCI showed through testimony and cross-examination of Staff's and the Utilities' witnesses on this subject that the Uniform System of Accounts permits the costs in question to be capitalized, but GCI did not prove that the only proper treatment is capitalization and not expensing. The Utilities' and Staff's witnesses each submitted written testimony indicating that either treatment is proper. Gregor Reb., NS-PGL Ex. 21.0 Corr., 12:242-256; Ostrander Reb., Staff Ex. 11.0 Corr., 10:207 – 11:222; Gregor Sur., NS-PGL Ex. 38.0, 4:73 – 5:87. The AG cross-examined Staff's and the Utilities' witness on this point, using an excerpt from the Uniform System of Accounts that had not been quoted or cited in GCI's witness' written testimony (AG Cross. Ex. 13). Staff's witness restated his agreement with the Utilities before reading language from the document, but he was not asked if it changed his opinion. Ostrander Tr. 8/30/11, 284:6 – 287:11. The Utilities' witness also acknowledged the language of the document but she was not asked if it changed her opinion. Gregor Tr. 9/2/11, 922: 12 - 925:9. The document (p. 11) includes the phrase "shall include", but that is immediately followed by "where applicable", and neither the document itself (apparently) nor any cross-examination indicated the meaning of the latter qualifying language. Also, the document (p. 12) says "'General administration capitalized' includes the portion of the pay and expenses of the general office and administrative and general expenses applicable to construction work", but nowhere did GCI define what this means and the costs the Utilities are currently capitalizing are far removed from the actual construction work, as indicated by the testimony cited above.

Accordingly, GCI's adjustment should be rejected, but, if it were to be adopted, then the costs in question must be added to Peoples Gas' rate base.

5. <u>Uncollectibles Expense – Use of Net Write-Off Method</u>

Staff proposes to use actual 2010 net write-offs as the method to determine the Utilities' uncollectibles expense for purposes of revenue requirements and their uncollectibles expense riders, Riders UEA and proposed UEA-GC, rather than the Utilities' percentage of revenues method, which is based on current period revenues and costs. Staff's proposal would result in a \$510,000 increase in uncollectibles expense in Peoples Gas' revenue requirement and a \$421,000 decrease as to North Shore. Kahle Dir., Staff Ex. 1.0, Scheds. 1.11N and 1.11P; Gregor Reb., NS-PGL Ex. 21.0 Corr., 7:148 – 8:156. Staff's proposal is very problematic and should not be adopted, for three reasons discussed here. A further problem is that Staff has not adequately addressed the tariff language changes required by its proposal. *See* Section VIII.A, *infra*.

First, if the Utilities were to switch to the net write-off method, then there would be no reliable method to determine how much of the actual write-offs are related to the Gas Charge as opposed to delivery rates, and that information would be needed to remove the gas cost related amount if the Commission approves Rider UEA-GC and for the Rider UEA-GC filing. Customer accounts are written off in total, they can include receivables from multiple periods, and the ratio of Gas Charges and delivery rates in customers' bills will vary between periods. The net write-off method would have unpredictable results and would lead to inaccurate reconciliations. In contrast, the Utilities' percentage of revenues method allows a more consistent comparison of Gas Charge revenues, gas-cost related uncollectibles expense, and ICC Form 21 data and is superior. The amount of Gas Charge revenues in any given actual or forecasted year is a known amount. Therefore, it is a simple calculation to multiply the Gas Charge revenues by the approved percentage for bad debt to determine the bad debt related to the Gas Charge. Gregor Reb., NS-PGL Ex. 21.0 Corr., 8:159-167; Grace Reb., NS-PGL Ex. 28.0, 38:831 – 39:849; Gregor Sur., NS-PGL Ex. 38.0, 5:103 – 6:117.

Second, the net write-off method would lead to a mismatch between revenues and the uncollectibles expense being recorded. While some degree of timing differences may be inherent in tracking riders, the net write-off method would cause much greater lags because the lag between the ultimate reconciliation of expense to the related revenue could lead, for example, to customers paying for high levels of write-offs related to years before they even were customers of the Utilities. Gregor Reb., NS-PGL Ex. 21.0 Corr., 8:167-174.

Finally, if the net write-off method were to be employed, then Staff's proposal is seriously flawed by using data from a single year. A six year average would be the minimum reasonable period for that method, because of the great variability in write-offs resulting from changing gas prices and the economy. However, this would not solve the problem of allocating the write-offs between Gas Charge and delivery rates. Gregor Reb., NS-PGL Ex. 21.0 Corr., 8:174 – 9:177; Gregor Sur., NS-PGL Ex. 38.0, 6:118-127. Staff's proposal should not be adopted.

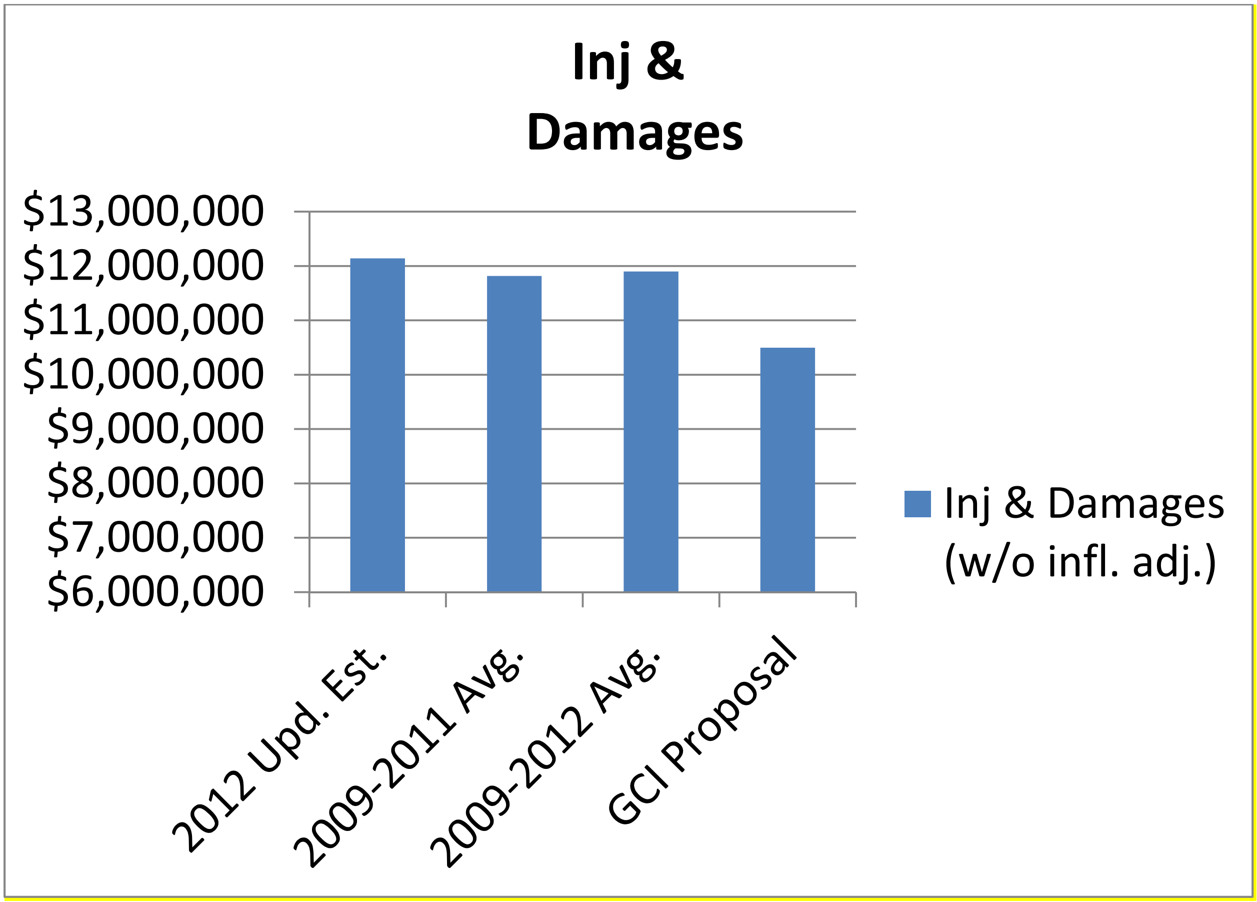
6. Administrative & General

a. Injuries and Damages Expenses

GCI proposes to reduce Peoples Gas' injuries and damage expenses by $3,077,000 from the level in Peoples Gas' direct and rebuttal figures, but GCI's proposal is erroneous. GCI's proposal is based on incorrect interpretation of a data request response and extrapolation based largely on a single year (2010) in which the level of this item was unusually low. Gregor Reb., NS-PGL Ex. 21.0 Corr., 11:223-236; Gregor Sur., NS-PGL Ex. 38.0, 3:47 – 4:67.

Peoples Gas, in its surrebuttal, reduced the amount in its revenue requirement for injuries and damages expense by $1,433,000 to $12,142,000, based on the most up to date forecast for the 2012 test year. Gregor Sur., NS-PGL Ex. 38.0, 3:47 – 4:67. No further reduction is warranted. There is no basis for rejecting the updated test year value.

Moreover, Peoples Gas' revised figure of $12,142,000 is very close to both: (1) the 2009-2011 actuals and 2011 updated forecast combined three year average (mean) of $11,817,667 and (2) the 2009-2010 actuals and 2011-2012 updated forecasts combined four year average (mean) of $11,898,750, in each instance even before correcting the 2009-2011 figures for inflation.[53] In contrast, GCI's proposal would set the level at $10,498,000, far below the averages. *See* Effron Reb., GCI Ex. 7.0, 14:309-313. The outlier nature of GCI's proposal versus the updated 2012 test year estimate and the averages is illustrated in the following table.



In the 2007 rate cases, the Commission approved use of the Utilities' historical test year injuries and damage expense levels, with one adjustment for an unusual item in the test year, rejecting a Staff-proposed downward adjustment based on a complicated multi-year average where slightly changing which years were used produced large differences. *Peoples 2007*, p. 57.

[53] The 2009 actual amount was $12,913,000 (PGL Ex. 5.1, p. 4, line 28, col. (F). The 2010 actual amount was $8,684,000. Gregor Sur., NS-PGL Ex. 38.0, 3:59-60. The updated forecasts for 2011 and 2012 are $13,856,000 and $12,142,000 respectively. *Id.* at 4:62-64.

In the 2009 rate cases, the Commission approved use of the Utilities' forecasted test year injuries and damage expense levels, again rejecting a Staff-proposed downward adjustment based on a multi-year average. *Peoples 2009*, pp. 84-85.

In the instant cases, the Commission again should reject the attempt to supplant the test year value (here an updated, already reduced figure) with a lower figure where there is no valid justification for rejecting the former in favor of the latter. GCI's proposal should be rejected.

b. <u>Adjustment to Account 921 - Office Supplies and Expenses</u>

The only contested issue with respect to Account 921 is addressed in Section V.C.4 of this Initial Brief. The only other proposed adjustment to these expenses (which related to cellular costs) was made, but later was correctly withdrawn, by GCI. Gregor Reb., NS-PGL Ex. 21.0 Corr., 12:242-246, 12:256-263; Effron Reb., GCI Ex. 7.0, 13:271-293.

c. <u>Rate Case Expenses</u>

(i) <u>Rate Case Expenses – Docket Nos. 11-0280/0281 (cons)</u>

The Utilities showed that their revised proposed rate cases expenses are just and reasonable, and the evidentiary record contains more than sufficient information for the Commission to so find consistent with Section 9-229 of the Act, 220 ILCS 5/9-229.[54] The Utilities, in planning and budgeting for the preparation and prosecution of these cases, sought to incur only prudent and reasonable rate case expenses. Factors identified in managing and estimating these costs included: (1) efficiencies resulting from simultaneous preparation and anticipated consolidation of Peoples Gas' and North Shore's rate case filings; (2) selection of outside counsel and expert resources with extensive experience in Illinois rate cases and other

[54] Section 9-229's title and text are: "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."

proceedings and negotiations of appropriate estimated hours of work and rates; (3) cost effective use of IBS to provide rate case support services; and (4) the extensive procedures involved in prosecuting a rate case after filing which include: the discovery process, analysis of Staff and intervenor direct and rebuttal testimonies, assistance with preparation of 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. The amounts originally estimated reflected prudent and reasonable budgets for the work of the outside consultants, the outside legal counsel, and applicable IBS personnel on the preparation and prosecution of these rate cases. These expenses were the subject of voluminous ongoing discovery, and they were updated and reduced by Staff in rebuttal (including supplemental rebuttal) and then by the Utilities in surrebuttal. Moy Dir., NS Ex. 6.0, 16:332-17:355; NS Ex. 6.2; Moy Dir. PGL Ex. 6.0, 6:338-17:361; PGL Ex. 6.2; Moy Reb., NS-PGL Ex. 22.0 2 Corr., 9:181-16:351; Ostrander Reb., Staff Ex. 11.0 Corr., 4:70 – 7:147 and Scheds. 11.1N, 11.1P Corr.; Ostrander Supplemental ("Supp.") Reb., Staff Ex. 20.0, 2:27 – 3:48 and Scheds. 20.1N, 20.1P; Moy Sur., NS-PGL Ex. 39.0 Corr., 7:145 – 10:193; NS-PGL Exs. 39.4N, 39.4P, 39.9N (Public and Confidential), 39.9P (Public and Confidential).

Staff's Proposed Adjustments. There is no dispute between Staff and the Utilities regarding the rate cases expenses of the instance cases, with one limited exception. As noted above, Staff presented proposed adjustments based on updating in its rebuttal, and the Utilities accepted those adjustments, with some further updating that further slightly reduced the expenses, in their surrebuttal. Ostrander Supp. Reb., Staff Ex. 20.0, 2:27 – 3:48 and

Scheds. 20.1N, 20.1P (Public and Confidential); Moy Sur., NS-PGL Ex. 39.0, 7:145 – 10:193; NS-PGL Exs. 39.4N, 39.4P (Public and Confidential).

The sole open item with respect to Staff's position is that Staff also proposed to disallow \$39,000 as to North Shore and \$54,000 as to Peoples Gas that reflected incentive compensation amounts relating to the Non-executive Incentive Compensation program included in the amounts relating to IBS personnel. Ostrander Supp. Reb., Staff Ex. 20.0, 2:27 – 3:48 and Scheds. 20.1N, p. 2, line 9, col. (g), and Sched. 20.1P, p. 2, line 9, col. (g) (Confidential). To simplify the issues, the Utilities agree that, to the extent the Commission agrees with Staff's proposed disallowances relating to the Non-executive Incentive Compensation program, discussed in Section V.C.1 of this Initial Brief, then to the same extent the aggregate \$93,000 at issue here should be removed.

Staff recommended that, if Staff's adjustments were approved, the Commission's Order should make the following conclusion:

> The Commission finds that the amounts of compensation for attorneys and technical experts to prepare and litigate this proceeding, as adjusted by Staff, are just and reasonable pursuant to Section 9-229 of the Act (220 ILCS 5/9-229).

Ostrander Reb., Staff Ex. 11.0 Corr., 7:142-147. The Utilities agree, except the phrase "adjusted by Staff" should be followed by "and updated in the Utilities' surrebuttal". Also, depending on how the Commission rules on the above \$93,000, the above language might need slight modification.

<u>GCI's Proposed Adjustments</u>. GCI proposed no adjustment to any particular rate case expenses. GCI's witness, Mr. Morgan, in his direct testimony, indicated that he needed additional information on the subject, noting some particular areas where he had potential concerns but not proposing any adjustments, but, as the Utilities understand his rebuttal testimony, he was satisfied by the information he later received. Morgan Dir., GCI Ex. 1.0 Corr., 21:14 – 22:5; Morgan Reb., GCI Ex. 6.0, p. 5. Instead, GCI's witness, for the first time in his

rebuttal, proposed a "50/50 sharing" of rate case expenses between the Utilities and customers, *i.e.,* to disallow 50% of the expenses. Morgan Reb., GCI Ex. 6.0, p. 7. He offers two grounds: (1) rate increases benefit shareholders and (2) sharing provides an incentive for controlling rate case expenses. *Id*. Mr. Morgan's proposal is inappropriate, for several reasons.

First, rate case expenses are a cost of doing business that the Utilities are entitled to recover. The Utilities have a legal right to rates that allow them the opportunity to recover fully their prudent and reasonable costs of service, and rates are required to be just and reasonable for the Utilities and their shareholders as well as customers, as shown in Section I.A.5 of this Initial Brief. The Commission should not set rates set below the utility's cost of service. Rate cases filed by a utility are the primary means by which rates are revised to meet with the above legal requirements. While the timing of rate cases is intermittent and unpredictable, when they occur they are a normal cost of doing business for a utility. Moy Sur., NS-PGL Ex. 39.0 Corr., 11:219-227.[55]

Second, the Utilities have ample incentives to control rate case expenses, such as the fact that they bear in the first instance but recover no carrying costs on these expenses, and the uncontradicted evidence shows they did manage these expenses in these cases, as discussed above and as reflected in the decrease from the levels proposed and allowed in their 2009 rate cases that GCI's witness himself noted. Moy Sur., NS-PGL Ex. 39.0 Corr., 10:204-206, 11:227-231; *see* Morgan Dir. GCI Ex. 1.0 Corr., 16:12-23.

Finally, Section 9-229 does not alter the foregoing legal and factual points. (Nor does the GCI witness claim that Section 9-229 supports his belated proposal.) Section 9-229 does not

[55] The Illinois Supreme Court has rejected requiring a utility to "share" reasonable amounts incurred in light of legal requirements. *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 121, 651 N.E.2d 1089, 1095 (1995) (reversing Commission Order directing the sharing of costs incurred by utilities under environmental laws).

provide for or support any "sharing" of rate case expenses.[56] Indeed, the Utilities' rate cases expenses in their 2009 rate cases were found just and reasonable, with the Commission referencing Section 9-229. *Peoples 2009*, p. 43. The Commission has approved recovery of rate cases expenses in numerous cases, including at least ten other rate cases in which it has approved rate case expenses and referenced Section 9-229.[57] Accordingly, the Commission should approve the Utilities' rate case expenses as revised in their surrebuttal.

(ii) Amortization of Rate Case Expenses Associated With Docket Nos. 09-0166/0167 (cons)

Staff proposed an adjustment to the amortization of the remaining approved 2009 rate cases expenses that will still be unamortized (not recovered) as of the 2012 test year, while GCI proposed outright rejection of recovery of these expenses. Neither proposal is correct.

Staff proposed that the calculation of the amount of 2009 rate case expenses to be amortized through the rates set in the instant case should be based on actual costs but capped by the level approved by the Commission in the 2009 rate cases, and also should exclude costs related to rehearing and appeals. The Utilities, in the interests of narrowing the issues, have agreed to the first of those two premises (as reflected in the Utilities' figures), but disagree with the exclusion of rehearing and appeal costs. Moy Sur., NS-PGL Ex. 39.0 Corr., 6:119-127, 7:133-143. Staff's proposal to exclude rehearing and appeal costs should not be adopted

[56] The Commission rejected GCI's proposal for a 50/50 sharing of charitable contributions in ComEd's 2010 rate case as contrary to Section 9-227 of the Act, 220 ILCS 5/9-227. *ComEd 2010*, p. 109. While Sections 9-227 and 9-229 differ in various respects, they each relate to recovery of a particular kind of expense, and neither provides for any "sharing" of that expense.

[57] *MidAmerican Energy Co.*, ICC Docket No. 09-0312 (Order Mar. 24, 2010), p. 43; *Illinois-American Water Co.*, ICC Docket No. 09-0319 (Order Apr. 13, 2010), p. 80; *Central Illinois Light Co., et al.*, ICC Docket Nos. 09-0306 Cons. (Order Apr. 29, 2010), p. 70; *Apple Canyon Utility Co., et al.*, ICC Docket Nos. 09-0548 (Order Sept. 9, 2010), pp. 20-21; *Consumers Gas Co.*, ICC Docket No. 10-0276 (Order Oct. 6, 2010), p. 4; *Whispering Hills Water Co.*, ICC Docket No. 10-0110 (Order Oct. 26, 2010), p. 10; *Aqua Illinois, Inc.*, ICC Docket No. 10-0194 (Order Dec. 2, 2010), pp. 13-14; *Galena Territory Utilities, Inc.*, ICC Docket No. 10-0280 (Order Dec. 15, 2010), pp. 5-6; *Northern Hills Water and Sewer Co.*, ICC Docket No. 10-0298 (Order Jan. 20, 2011), pp. 5-6; *ComEd 2010*, pp. 65-92 (also providing for a later rulemaking).

because: these processes are a common part of litigation of a general rate case, as exemplified by the pending appeals in the Utilities' 2007 and 2009 rate cases and the appeals from ComEd's 1999, 2001, 2005, 2007, and 2010 rate cases Orders. *Id.* at 6:127 – 7:131.

GCI proposed (inconsistently with its normalization proposal) that even though the expenses in question were approved for recovery in the 2009 rate cases, recovery now should be barred on the theory that recovery nonetheless somehow constitutes retroactive and single issue ratemaking. That is wrong. Moy Sur., NS-PGL Ex. 39.0 Corr., 5:103 – 6:118. Amortization of the 2009 rate cases expenses already was approved by the Commission's Order in those cases. *Peoples 2009*, pp. 42-43. The unamortized amount to be recovered through the rates being set here does not exceed what was approved then, as noted above. Illinois utilities in past rate case proceedings have been allowed by the Commission to recover remaining unamortized prior rate case expenses while seeking approval to recover new rate case expenses. This situation was addressed in ComEd's 2010 rate case, in which the Commission approved recovery of unamortized approved rate case expenses from ComEd's prior (2007) rate case as well as that 2010 case (and provided for the subject of rate case expenses to be addressed in a rulemaking process, as noted earlier). *ComEd 2010*, pp. 59, 68; Moy Sur., NS-PGL Ex. 39.0 Corr., 6:108-113. Similarly, in ComEd's 2007 rate case, the Commission allowed recovery of unamortized approved rate case expenses from ComEd's prior (2005) rate case as well as that 2007 case, rejecting Mr. Effron's claim that the unamortized 2005 case expenses should be disallowed. *ComEd 2007*, pp. 70-74. There is no basis for a different result here.

(iii)<u>Normalization of Rate Case Expenses</u>

GCI (inconsistently with its "50/50 sharing" proposal) also proposes to "normalize" rate case expenses. However, GCI has never given a good reason for doing so. Normalization can lead to over- or under-recovery just like the Commission's accepted amortization method, and the proposal seems premature in light of the rulemaking ordered in *ComEd 2010*, and thus both Staff and the Utilities oppose GCI's proposal. Ostrander Reb., Staff Ex. 11.0 Corr., 12:247 – 14:285; Moy Reb., NS-PGL Ex. 22.0 2 Corr., 15:330 – 16:342. GCI's proposal is inappropriate.

d. Gas Transportation Administrative Costs

The subject of Gas Transportation administrative charges is addressed in Sections XI.C, XI.D.1, and XI.E.1 of this Initial Brief. Staff proposes adjustments to those charges, which would not affect the Utilities' base rate revenue requirements, but would affect the total revenues of the Utilities. *See* Sackett Reb., Staff Ex. 18.0, 4:68 – 6:119. Staff's proposal is refuted in Sections XI.C, XI.D.1, and XI.E.1.

e. Solicitation Expense

A portion of each of the Utilities' revenue requirements is amounts directly charged or allocated to them by their affiliate, IBS. Staff challenges whether the Utilities have appropriately reflected in their forecasts for the 2012 test year the effect of IBS recovering from another affiliate, Peoples Energy Home Services ("PEHS"), the proper amount for solicitation services provided by IBS to PEHS. The solicitations relate to the Pipeline Protection Program ("PPP") offered by PEHS. However, the Utilities have reflected appropriate and reasonable cost-based figures for those IBS solicitation revenues in their forecasts for the 2012 test year, a total of $16,572, so no adjustment is proper or necessary. Gregor Sur., NS-PGL Ex. 38.0, 7:142 – 8:164, 9:171-183. Any errors made by IBS in prior years by not billing PEHS the right amounts do not alter the correctness of the 2012 test year figures. *Id*. at 9:184-190.

Staff proposes that the figures should instead be calculated based on as estimate of the market value of the solicitation services provided by IBS to PEHS, but the correct calculation is cost-based under the Master Non-Regulated Affiliated Interest Agreement. Gregor Sur., NS-PGL Ex. 38.0, 7:138-141, 8:165-170.

7. Depreciation

a. Depreciation Expense on Forecasted Additions

As discussed in Section IV.C.1.a of this Initial Brief, the Utilities, in the interests of narrowing the issues, accepted Staff's proposed adjustment related to forecasted plant additions. There were errors in Staff's figures for the derivative impacts on depreciation expense of that plant additions adjustment, but the errors were corrected in the Utilities' corrected surrebuttal. Moy Sur., NS-PGL Ex. 39.0 Corr., 5:86-97. The Utilities believe that the corrected figures for the derivative impacts are not contested.

b. Derivative Adjustments from Contested Adjustments

Setting aside the corrections discussed in Section V.C.7.a, *supra*, which the Utilities understand to have been resolved, the Utilities do not believe that there are any disputes over the correct calculation of depreciation expense impacts of contested plant adjustments. When the Utilities do contest a plant adjustment, then, of course, they also oppose the associated derivative impacts, including the impact on depreciation expense.

8. Revenues

a. Repair Revenues

Staff proposes adjustments based on the theory that the Utilities' should charge PEHS the same rate for repairs as the Utilities charge customers who request repair service, calculating the adjustments based on the rate charged to customers, multiplied by the number of each type of repair performed for PEHS, and then subtracting what PEHS already paid the Utilities. Gregor Sur., NS-PGL Ex. 38.0, 9:191 – 10:196. Staff's proposal is incorrect.

Under the Commission-approved Services and Transfers Agreement, which applies here, the Utilities are to bill PEHS at the Fully Distributed Cost (the "FDC") of providing the service. Gregor Sur., NS-PGL Ex. 38.0, 10:197-204. The Utilities provided support for the FDC calculation. *Id.* at 10:201-204.

In 2008-2010, the Utilities missed billings totaling $7,174 for Peoples Gas and $910 for North Shore, and they originally did not include this item in their forecasted 2012 test year figures, but the Utilities' revised revenue requirements in surrebuttal reflect the correct amounts. Gregor Sur., NS-PGL Ex. 38.0, 10:205-214. The Utilities are required to charge PEHS the FDC, and are not required to charge the same amount charged to customers. *Id*. at 11:215-220.

b. Other Issues Relating to PEHS and PEPP, <u>Including Staff Request for Investigation</u>

Staff proposes that the Utilities should be required to file a petition with the Commission if they wish to continue to support the PPP offered by PEHS, to be followed by an investigation, on the grounds of IBS' and the Utilities' errors in prior years relating to solicitation expense and repairs revenues. Sackett Reb., Staff Ex. 18.0, 4:62-65. Staff's proposal should not be adopted. The amounts involved do not justify the burdens and costs of such steps. The impact of the 2012 test year solicitation revenues, properly calculated, on the Utilities' forecasts are just $16,572, as noted above. The missed billings for repairs in 2008 to 2010 were just a total of $7,174 for Peoples Gas and $910 for North Shore, as noted above. Larger amounts potentially would be at stake if the solicitation and repairs amounts were to be calculated as Staff proposes, but, as discussed earlier, Staff's proposals are incorrect.

c. <u>Warranty Products (Revenue and Non-Revenue)</u>

The Utilities did not make any proposal on this subject.

D. **Taxes Other Than Income Taxes (Payroll and Invested Capital Taxes) (Uncontested Except for Derivative Adjustments from Contested Adjustments)**

The Utilities do not believe there is any contested proposal as to Taxes Other Than Income Taxes, apart from derivative impacts of contested proposals on other subjects. When the Utilities contest an adjustment elsewhere, they also oppose the derivative impacts.

E. **Income Taxes (Including Interest Synchronization) (Uncontested Except for Derivative Adjustments from Contested Adjustments)**

The Utilities do not believe there is any contested proposal as to Income Taxes, apart from derivative impacts of contested proposals on other subjects. When the Utilities contest an adjustment elsewhere, they also oppose the derivative impacts.

F. **Gross Revenue Conversion Factor**

1. **Uncollectible Rate**

The Utilities correctly have used the Gross Revenue Conversion Factor ("GRCF") of 1.711941 for North Shore and 1.744262 for Peoples Gas. Moy Sur., NS-PGL Ex. 39.0 Corr., 13:274-279. Staff's proposed net write-off method for uncollectibles expense would affect the uncollectibles rate portion of the GRCF calculations for the Utilities, *id*. at 13:279-282, but Staff's proposal should not be adopted, as discussed in Section V.C.5 of this Initial Brief, *supra*.

2. **Derivative Adjustments from Contested Adjustments**

The Utilities do not believe that, apart from Section V.F.1, *supra*, there is any contested proposal related to the GRCF as such. Contested adjustments affect the level of revenues to which the GRCF is to be applied, but there is no issue as to the method of that calculation.

VI. RATE OF RETURN

A. Overview of the Parties' Positions

The Utilities propose test year capital costs based on consistent methodologies grounded on the realities of the highly volatile financial markets in which they must compete for capital. So measured, Peoples Gas' overall rate of return on rate base in 2012 is 8.11%. This cost is based on a capital structure of 56% equity and 44% long-term debt, a cost of equity of 10.85%, and an average cost of long-term debt of 4.62%. NS-PGL Ex. 35.4P. North Shore's overall capital cost is 8.50%, based on a capital structure of 56% equity and 44% long-term debt, a cost of equity of 10.85%, and an average cost of long-term debt of 5.51%. NS-PGL Ex. 18.1N.

The Utilities' proposed costs of capital are based on the realities of their actual capital structures and the financial conditions that are likely to exist in 2012:

- The Utilities' proposed capital structure is the same structure the Commission authorized in the Utilities' 2007 and 2009 rate cases and is consistent with the structures the Utilities have actually maintained since then. *Peoples 2007*, p. 73; *2009 Peoples*, p. 93; Gast Dir., NS Ex. 2.0, 7:117 – 8:125; Gast Dir., PGL Ex. 2.0, 7:116-124.
- The Utilities' proposed cost of equity is based on the analyses and recommendation of their cost of equity expert, Mr. Paul Moul, who followed the same methodology and used the same mathematical models that he followed and used in the Utilities' last two rate cases. In applying the models to estimate the Utilities cost of equity, Mr. Moul considered information available to and typically relied on by investors and financial analysts, and applied his judgment to the operation and results of the models. Mr. Moul's updated cost of equity recommendation of 10.85% represents a

modest increase to the Utilities' current authorized ROEs of 10.23% (Peoples Gas) and 10.33% (North Shore). Moul Reb., NS-PGL Ex. 19.0 REV, 6:122 – 7:151; NS-PGL Exs. 19.3 – 19.10.

- The Utilities' proposed costs of long-term debt are comprised of the actual costs of the Utilities' existing issuances, plus the forecasted costs of the issuances they expect to make in the test year. *See* NS Ex. 2.2, NS-PGL Ex. 35.3P.

By contrast, Staff's and GCI's proposed costs of capital are based on inconsistent methodologies that ignore the realities that drive the Utilities' actual capital costs, and rely instead on their opinions about what the Utilities' costs should be. Thus, Staff proposes to replace the Utilities' actual, historical and authorized capital structures with imputed, artificial ones that contain less equity and more debt, including short-term debt, and significantly more risk. Nothing has changed with respect to how the Utilities manage their capital, but Staff argues that the Utilities' risk should be increased to the historical risk of the Gas Group. Staff's proposal has nothing to do with the Utilities' actual and expected use of capital in the test year, or for that matter with the Gas Group's forecasted capital structures. More important, Staff's proposed degradation of the Utilities' financial strength would set the Utilities up for a downgrade in their credit ratings, which would lead to higher capital costs and higher rates. *See* Section VI.B of this Initial Brief.

Staff's proposed cost of long-term debt for Peoples Gas likewise diverges from reality. It includes the estimated cost of $51 million in debt that does not exist and is not forecasted to exist during the test year. *See* Section VI.C of this Initial Brief.

Staff proposes a cost of equity – 8.75% – which if adopted would translate to a decrease in Peoples Gas' authorized ROE by 148 basis points and a decrease in North Shore's authorized

ROE by <u>158 basis points</u>. *See* Section VI.E of this Initial Brief. The mid-point of GCI's proposed ROE range – 8.02% - would be even more draconian. Any return in the ballpark of Staff's or GCI's proposals "would send a strong negative signal to the financial markets that the Commission does not support the Utilities' current financial position," and would likely result in higher capital costs for the Utilities and higher rates for their customers. Moul Reb., NS-PGL Ex. 19.0 REV, 3:55-59; *see also* Fetter Reb., NS-PGL Ex. 20.0, 14:297-300.

1. <u>The Context of the Commission's Cost of Capital Decisions</u>

The Commission accurately summarized the Utilities' "entitlement to a fair and reasonable return on its investment" in their last rate cases:

> 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 2009, pp. 89-90 (citations omitted).

There is considerable agreement in the record on the importance to <u>customers</u> of allowing a utility to recover its costs of capital. Staff agreed that the Commission should strive to balance shareholder and customer interests by setting the utility's ROR equal to its overall cost of capital. Kight-Garlisch Dir., Staff Ex. 4.0, 2:34-37. Mr. Thomas agreed that customers have in interest in preventing unnecessary increases in the utility's capital costs, and that maintaining its financial strength and credit ratings are ways to do so. Tr. 9/6/11, 954:6-13. If the Commission were to set the authorized ROR below the utility's actual cost, "the financial strength of the utility could deteriorate, making it difficult for the utility to raise capital at reasonable cost. Ultimately, the utility's inability to raise sufficient capital would impair service quality."

Kight-Garlisch Dir., Staff Ex. 4.0, 2:38-42; *see also* Thomas Tr. 9/6/11, 953:18 – 954:9. Thus, utility shareholders and customers share an interest in rates that maintain the utility's financial strength, strong credit ratings and lower capital costs.

Steven Fetter, a former chair of the Michigan commission and former officer of the Fitch credit rating agency, described the unique risks that affect a utility's capital costs. A natural gas utility's business is naturally capital-intensive and its duty to serve requires it to go to the financial markets to raise capital for investment in its system and procure sufficient gas supply regardless of the state of the financial or natural gas markets. Non-regulated companies are much better able to defer investment and spending decisions in response to unfavorable market conditions. Fetter Reb., NS-PGL Ex. 20.0, 7:144 – 8:157. These are not theoretical concerns. The Utilities were required to access the capital markets three years ago when the markets almost shut down in the wake of the financial crisis, and were able to do so due to their financial strength and relatively strong credit ratings. *Id.* at 10:196-211; Gast Reb., NS-PGL Ex. 18.0, 3:56-59.

Mr. Fetter also explained the increasing importance of this Commission's ratemaking decisions on the Utilities' ability to maintain investment grade credit ratings and reasonable capital costs. The quality and direction of regulation, in particular the ability to recover costs and earn a reasonable return, are among the most important considerations when a credit rating agency assesses utility credit quality and assigns credit ratings. Fetter Reb., NS-PGL Ex. 20.0, 8:167 – 9:174. It is also a key consideration in investors' decisions about whether to invest in utilities as opposed to other industries. "Utility investors understand and accept the role of pervasive regulation, but they seek from the regulatory process decision-making that is fair, with a significant degree of predictability." *Id.* at 9:186-188. The financial markets' focus on the quality and direction of regulation has sharpened following the 2008 credit crisis and the volatility in credit access and cost that has ensued. *Id.* at 10:196 – 11:227.

In this respect, the financial markets remain at higher levels of volatility than before the financial crisis. Moul Reb., NS-PGL Ex. 19.0 REV, 8:164 – 9:186. Indeed, in the period between rebuttal filing dates in these rate cases, the stock market's volatility shot up to levels even higher than they were during and immediately after the financial crisis. Moul Sur., NS-PGL Ex. 36.0, 2:42-44, 3:73-74; Moul Reb., NS-PGL Ex. 19.0 REV, 9:180-181. "[H]igher market volatility signifies increased risk, and investor-required returns will ratchet upward in reaction to this higher risk." Moul Sur., NS-PGL Ex. 36.0, 4:83-84.

In short, the quality and direction of the Commission's regulation of Illinois utilities directly affect the Utilities' cost of capital. The evidence in this record is that the Utilities' risk is substantially increased as a result. Regulatory Research Associates ("RRA"), a primary source for investors on the quality and direction of regulation among state commissions, currently rates Illinois among the lowest three states in the country. Fetter Reb., NS-PGL Ex. 20.0, 11:229 – 12:239. Although S&P upgraded Illinois from "least credit supportive" to "less credit supportive," the agency has more recently expressed "rater's remorse" in light of the Commission's decision in Ameren's last rate case, which included a 9.19% ROE and was characterized by S&P as "not conducive to credit quality." *Id.* at 12:240 – 13:271; Fetter Sur., NS-PGL Ex. 37.0, 2:35 – 3:44.[58]

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[58] At the hearing, the Utilities sought to introduce into evidence a report pertaining to the credit quality of the Utilities published by S&P on August 26, 2011, as an update to Mr. Fetter's testimony. The ALJs sustained GCI's objection to the admission of the report on the grounds that it would be unfair to introduce into evidence "any document for whatever reason at this late date," and asked the parties "<u>to confine your questions and testimony to the documents that have been previously available to all the parties</u>." Tr. 8/31/11, 374:1 – 377:5 (emphasis added). Nevertheless, during cross-examination of Mr. Moul, Staff was allowed, over the Utilities' objection (GCI did not object), to introduce into evidence updated information regarding treasury bond yields (Staff Cross Ex. 5) and interest rate forecasts (Staff Cross Ex. 6), even though the documents and information had not been relied upon previously by Staff or disclosed to any party to the proceeding. *See* Tr. 8/31/11, 470:14 – 484:12. Moreover, Staff's

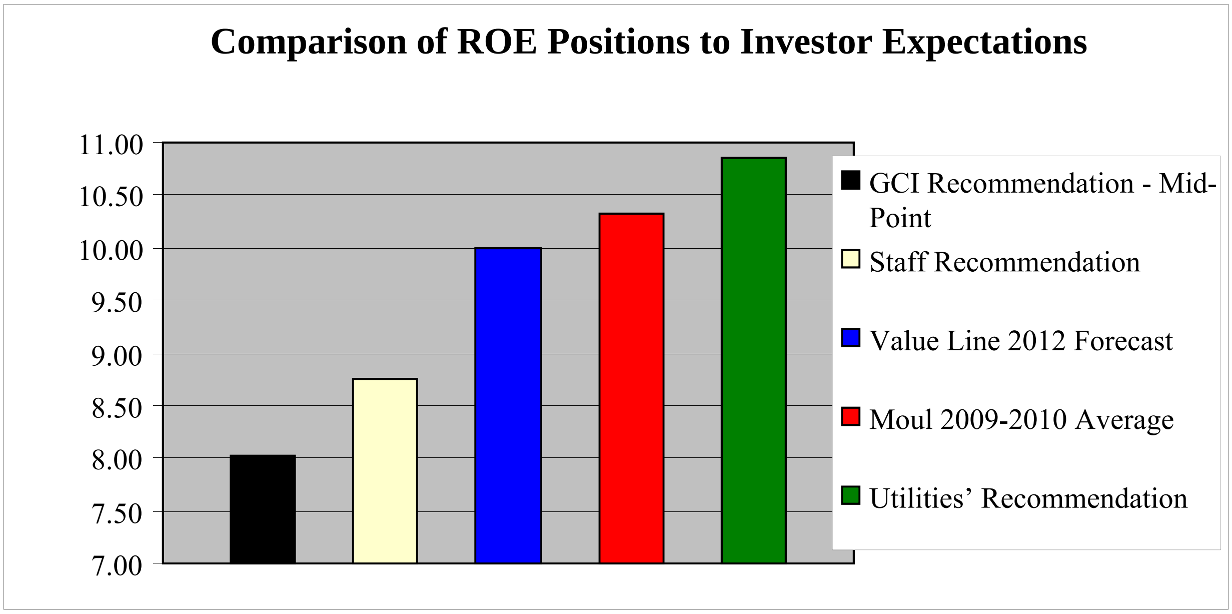
Thus, the state commissions play a very real part in "making the market" for utility capital. The Utilities' current (10.33% North Shore and 10.23% Peoples Gas) and proposed (10.85%) ROEs are well within the range of utility ROEs recently authorized by this Commission and other state commissions throughout the country. Fetter Reb., NS-PGL Ex. 20.0, 13:285 – 14:290; Moul Reb., NS-PGL Ex. 19.0 REV, 3:48-49; NS-PGL Exs. 20.2 and 20.3. According to Mr. Moul, the average return that was set for energy utilities nationally in 2009-2010 was 10.32%. Moul Reb., NS-PGL Ex. 19.0 REV, 2:44 – 3:48; NS-PGL Ex. 19.1.

By contrast, the Staff and GCI proposed ROEs are off the bottom of the charts. <u>The returns proposed by Staff and GCI would be lower than any ROE this Commission has authorized for any natural gas utility since at least 1972.</u> Schott Reb., NS-PGL Ex. 17.0, 6:128-132. They would also be lower than any ROE authorized anywhere in the country in the last two years, and there has been only one (in Connecticut, the state rated the absolute lowest for regulatory quality by RRA) as low as Staff's 8.75% proposal and none near the mid-point of GCI's proposals in the last five years. Moul Reb., NS-PGL Ex. 19.0 REV, 3:51-53; NS-PGL Ex. 19.1; Fetter Reb., NS-PGL Ex. 20.0, 13:285 – 14:290; NS-PGL Ex. 20.2. Even over the last <u>twenty</u> years, there have been no ROEs near GCI's level and only the lone Connecticut return at the level of Staff's proposal. Fetter Reb., NS-PGL Ex. 20.0, 14:291-296; NS-PGL Ex. 20.3.[59]

cross-examination on these documents consisted of nothing more than having the witness authenticate the two exhibits, read parts of one, and then moving them into evidence. *Id.* Thus, Staff used the cross-examination as a vehicle to offer new evidence. Allowing into evidence only the updated data proposed by Staff was unfair and prejudicial to the Utilities, especially with respect to Staff Cross Ex. 5, which included data that was not available prior to August 22, 2011, the date on which the Utilities were required to submit their surrebuttal. *Id.* 474:14 – 475:14. If not corrected in the ALJs' Proposed Order, the Utilities reserve the right to raise this evidentiary issue at the exceptions stage, on rehearing and/or appeal of this matter.

[59] Staff finds the lone Connecticut decision at 8.75% acceptable because it did not result in credit rating downgrade. That return was set for a utility whose credit rating was already at BBB, just one step above the lowest investment-grade rating, and S&P warned that the utility could be downgraded absent "constructive regulatory outcomes" in the future. Fetter Sur., NS-PGL Ex. 37.0, 3:54 – 4:82.

Against this backdrop of real-world financial market data, the Utilities' proposed ROE is well within investor expectations, whereas Staff's and GCI's proposals are so extremely low that they are unworthy of serious consideration. This is shown in the table below, that compares the Utilities, Staff and GCI proposed ROEs against the evidence of recent average utility ROEs and forecasted natural gas utility returns:



The Commission should give these facts great weight in evaluating the credibility of the results of the mathematical cost of equity models presented by the parties to estimate investor-required returns. Staff and GCI are effectively asking the Commission to believe that investors would be willing to invest in the Utilities at returns not only lower than they could currently earn by investing elsewhere, but at returns as low or lower than any utility has been authorized anywhere in the country. In today's uncertain financial markets, the Commission should ask itself, what investor would reasonably invest in the Utilities at the Staff and GCI proposed returns?

Given their positions, it is not surprising that Staff and GCI would prefer that the Commission ignore, or at least minimize its consideration of, this real-world information. They urge the Commission to focus primarily if not exclusively on their model results. McNally Reb., Staff Ex. 14.0, 37:788 – 38:809; Thomas Reb., GCI Ex. 10.0, 2:38 – 10:249. But each admit that the models require the analysts to make subjective choices about which models to use, what data to use and how to interpret the output. McNally Tr. 8/31/11, 504:6-20; Thomas Tr. 9/6/11, 951:4 – 952:3. Each of the models also has theoretical shortcomings that can misstate a firm's cost of equity. McNally Tr. 8/31/11, 504:21 – 505:3; Thomas Tr. 9/6/11, 945:20 -949:6. At best, these models can only <u>model</u> the real world. When models and reality diverge, as they do here, the only conclusion is that the models are imperfect, not that the models should control over reality.

The Commission has recognized the shortcomings of relying excessively on mathematical models to set utility returns. The Commission has recognized as well the need to consider the real-world information that is relied on by actual investors in setting the Utilities' actual costs of capital. In the Utilities' last rate cases, the Commission rejected the Staff/GCI head-in-the-sand position and recognized that this kind of evidence must be taken into account:

> As prudent regulators we must be cognizant of this context because each of the financial models is theoretical and has its own limitations. The models are also highly dependent on analyst judgment as to the inputs, and therefore <u>are susceptible to manipulation</u>. Although these models provide the best information of what we need for the purposes at hand, their limitations require that we also consult general financial market information to ensure that the model results presented us are <u>generally consistent with real world conditions</u>, and to guide our determination of reasonable rates of return on equity based on the models that we deem appropriate for our consideration.

Peoples 2009, p. 123 (emphasis added).

Mr. Fetter, who also testified in the Utilities' last rate cases, emphasized from his experience as a regulator that "there is value from such data because it helps regulators to gain an understanding of investor perceptions and expectations. This is important for regulators to know because the utilities under their jurisdiction compete with other utilities throughout the country for capital." Fetter Sur., NS-PGL Ex. 37.0, 5:91-94. Mr. Fetter cautioned that ignoring the very information on which investors rely and engaging in a purely theoretical exercise to determine utility ROEs "could be detrimental to ratepayer interests." *Id.* at 6:138 – 7:139.

As it makes its decisions on their capital costs for the 2012 test year, the Utilities urge the Commission to choose reality over opinion and to consider carefully the potential consequences of its decisions on the Utilities' actual financial strength and their actual capital costs.

2. Staff's Ever-Changing Methods

The Utilities have had three rate cases since 2007. A pattern has emerged over the course of those cases that casts doubt on the reliability of Staff's proposals on capital costs. In each case, Staff has used different methodologies to justify extreme positions. Equally important, Staff has been reluctant to explain its changes in methodology.

In the Utilities' last rate case, Staff changed its DCF methodology from the "constant" version of the model to the "non-constant" version. The Commission was not satisfied with Staff's explanation for the change:

> What is lacking in the evidence, however, is a sufficient explanation of what circumstances in the current case would warrant such a preference. We find that the reasons for Staff's switch to the non-constant growth version of the DCF model require additional inquiry. After consideration of the record, we reject 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. Rather we will require a more robust showing that application of the [non-]constant model is appropriate.

Peoples 2009, p. 125.

In this case, Staff changed its methodologies again, in three significant ways, and provided no explanation for the changes.

- After accepting the Utilities' proposed capital structures (which were the same as the Utilities propose in this case) in the Utilities' last two rate cases,[60] Staff presented comparisons of the Utilities to the Gas Group under S&P's financial risk matrix in order to justify imputing artificial and substantially weaker capital structures than the Utilities' actual ones. Staff's comparisons were highly subjective, fraught with error and misguided; indeed, Staff's proposals are contrary to customer interests. *See* Section VI.B.2 of this Initial Brief. But just as important, Staff offered no explanation for why, after accepting the Utilities actual capital structures in two prior cases, Staff found it necessary or even appropriate to adopt a novel methodology to justify weaker structures and higher risk.
- Staff in the Utilities' last two rate cases accepted Mr. Moul's Gas Group for the mathematical ROE models without presenting any analysis. *Peoples 2009*, p. 124; *Peoples 2007*, p. 78. In this case, after accepting the Gas Group for this purpose for the <u>third</u> time, Staff presented – on rebuttal, just two weeks before the hearing – a "principal components analysis" and for the first time took issue with comparability of the Gas Group and the Utilities. This belated analysis appears to have been designed to reach a desired result, namely a higher investment risk for the Gas Group than at least one of the Utilities. *See* Section VI.E.1.b. of this Initial Brief. But just as important, Staff offered no explanation for why, after not questioning Mr. Moul's consistent proxy group methodology three times, it was necessary or appropriate to do so at the rebuttal stage in these cases through a new analysis.

[60] *Peoples 2009*, pp. 91-92 (Staff requested a decision on whether short-term debt should be included in the Utilities' capital structure, which is a separate issue addressed in Section VI.B.1. of this Initial Brief); *Peoples 2007*, p. 73.

- In the Utilities' last two rate cases, after applying its financial models, Staff performed a financial risk analysis comparing the Utilities to the Gas Group to propose downward adjustments to the Utilities' ROEs. *Peoples 2009*, pp. 105-106; *Peoples 2007*, pp. 80-81. In this case, Mr. McNally presented no such analysis, again without explanation. *See* McNally Dir., Staff Ex. 5.0, 18:325 – 19:354. So the Utilities performed the analysis using Staff's proposed imputed capital structures and revenue requirements and found that it generated a 23-basis-point <u>upward</u> adjustment of their ROEs. *See* Section VI.B.2.c. of this Initial Brief.

The pattern of ever changing and inconsistent methodologies to reach consistently low capital cost results suggests that Staff is not approaching cost of capital with the intent of making recommendations that balance utility shareholder and customer interests, as it claims. Kight-Garlisch Dir., Staff Ex. 4.0, 2:33 – 3:44. The pattern at least creates the perception that Staff has become partisan and pursues reductions in utility capital costs as a policy objective. The Commission should, as it did in the Utilities' last rate case, reject unexplained shifts in methodology and set RORs based on the realities of the financial markets in which the Utilities compete for capital.

B. <u>Capital Structure</u> (Both Utilities)

For 2012, the Utilities propose no changes to their currently authorized capital structure of 56% equity and 44% long-term debt. This is the same capital structure that the Commission reviewed and approved in the Utilities' last two rate cases. *Peoples 2009*, p. 93; *Peoples 2007*, p. 73. This structure approximates the Utilities' actual capital structures over the past several years, including 2010. Gast Dir., NS Ex. 2.0, 7:119 – 8:125; NS Ex. 2.3; PGL Ex. 2.0, 7:119-124; PGL Ex. 2.3. More important, it supports the Utilities' current "A" issuance credit ratings, ratings that have allowed the Utilities to access the capital markets and obtain capital at reasonable cost even in the wake of the credit crisis of 2008-2009. Gast Reb., NS-PGL Ex. 18.0, 3:52-63.

Staff, by contrast, proposes to "impute" capital structures for the Utilities. By "impute" Staff means to replace the Utilities' actual, authorized, historical and forecasted capital structures with hypothetical capital structures that reflect Staff's opinion that the Utilities' financial strength should be degraded and their investment risk increased, even if that resulted in credit rating downgrades and increased capital costs. (At the same time it seeks to increase the Utilities' risk, Staff argues that the Utilities' ROEs should be <u>decreased</u>, and significantly so.)

Replacing a utility's actual forecasted capital structure with an imputed one is an extraordinary measure that the Commission takes only upon a convincing demonstration that the utility's customers would otherwise be unfairly burdened. "[I]mputing a hypothetical capital structure for ratemaking purposes to determine a utility's rates is a serious adjustment, and should only be adopted when a utility's actual capital structure is found to be unreasonable, imprudent, or unduly affected by such circumstances as double leverage so as to unfairly burden the utility's customers." *Illinois Commerce Comm'n v. Northern Ill. Gas Co.,* ICC Docket No. 87-0032, 1988 WL 1533285 at *23 (Order Jan. 20, 1988); *see also Northern Ill. Gas Co.,* ICC Docket No. 08-0363 (Order on Rehearing Oct. 7, 2009), p. 12.

The evidence in this record does not meet that standard. To the contrary, the imputed capital structures Staff proposes would be unreasonable and imprudent because they would degrade the Utilities' financial strength and threaten them with credit rating downgrades. The resulting increase in capital costs would unfairly burden the Utilities' customers.

Staff proposes to weaken the Utilities' capital structures in two ways – by including short-term debt and reducing the amount of equity. Weakening the Utilities current capital structures, structures which have allowed them to maintain reasonably strong credit ratings, "could put downward pressure on the Utilities' current credit ratings." Fetter Reb., NS-PGL Ex. 20.0, 15:310-319. Staff's proposals to weaken the Utilities' capital structures are not only unnecessary and harmful to the Utilities' shareholders and customers alike, but they are also unsupported by the evidence.

1. The Utilities Do Not Use Short-term Debt to Fund Rate Base

Only two rate cases ago, Staff supported precisely the same capital structure the Utilities propose to continue to use in 2012. *Peoples 2007*, p. 73. In the Utilities' last rate case, Staff did an about face and urged the Commission to impute short-term debt into the Utilities' capital structures. The Commission rejected Staff's proposal, citing the Utilities' evidence "that they issue short-term debt only temporarily to manage short-term cash flows at certain times, typically at year-end when higher winter revenues have not been collected and season[al] cash requirement[s] are at their highest and in late summer months when revenues are at their lowest." *Peoples 2009*, p. 93. "Just as significant," the Commission found, "only two years ago, the Commission approved the same capital structure that the Utilities propose in this case; the record shows no difference between how the Utilities use short term debt today and how they used it at that time." *Id.* (emphasis added).

In these rate cases, Staff did not allege any such differences. Rather, Staff simply asserted that if capital is fungible, then any short-term debt issued by the utility must fund a portion of rate base "unless it is shown that short-term debt does not support rate base." Kight-Garlisch Reb., Staff Ex. 13.0, 2:29. Staff does not dispute that the Utilities continue to use short-term debt exactly as they have since 2007, namely to finance temporary, seasonal cash requirements. Gast Reb., NS-PGL Ex. 18.0, 12:225-230. Therefore, the Utilities <u>have</u> shown that their short-term debt does <u>not</u> support rate base. *See Northern Ill. Gas Co.,* ICC Docket No. 04-0779 (Order Sept. 20, 2005), pp. 70-72 (finding no "material changes in circumstances since Nicor's last rate case that would lead to the inclusion of short-term debt this time around.").[61] The Commission should reject Staff's unsupported proposal to impute short-term debt into the Utilities' capital structures.

2. The Utilities' Proposed Capital Structure Is Reasonable and Necessary to Maintain Their <u>Financial Strength and Current Credit Ratings</u>

As noted above, the Utilities propose no change to their current authorized and actual capital structure comprised of 56% equity and 44% long-term debt. However, if the Commission adjusts the Utilities' capital structures for ratemaking purposes, the Utilities would manage their actual capital structures to those authorized. Otherwise, their shareholders would bear the cost of maintaining capital structures that vary from those authorized. Gast Sur., NS-PGL Ex. 35.0, 7:147 – 8:152.

In another unexpected deviation from its positions in the Utilities' 2007 and 2009 rate cases, Staff proposed in the instant cases to impute capital structures that contain much less equity and proportionally much more debt (whether short-term debt is included or not) than the Utilities' actual capital structures. Staff would have the Commission decrease Peoples Gas' equity ratio from 56% to 49% and North Shore's equity ratio from 56% to 50%. Kight-Garlisch Reb., Staff Ex. 13.0, 7:118 – 8:142.

[61] Staff's assertion on rebuttal that "the Companies have stated that they fund the difference between rate base and 'permanent capital' with short-term debt" (Kight-Garlisch Reb., Staff Ex. 13.0, 2:30-31) was misleading. The referenced data request responses, NS-PGL Exs. 35.1P and 35.1N, show that the Utilities' "statement" referred to a single point in time (December 31, 2012) and that, but for that instance the Utilities fund differences between rate base and permanent capital with <u>cash</u>. Gast Sur., NS-PGL Ex. 35.0, 4:65-71.

Staff asserted that these adjustments are necessary because the Utilities have too little risk as compared to the Gas Group. Kight-Garlisch Dir., Staff Ex. 4.0, 5:85 – 9:149. Staff's solution to this non-existent problem is to weaken the Utilities' capital structure and to increase their risk to levels that Staff believes are appropriate.

Staff proposes to increase the Utilities' financial risk from "Intermediate/Significant" profile to the "Significant/Aggressive" profile. Kight-Garlisch Dir., Staff Ex. 4.0, p. 5, Table 1; Kight-Garlisch Reb., Staff Ex. 13.0, 6, Table 1. Yet Staff underestimates the true damage of its proposal. At Staff's proposed capital structures and the financial ratios that would result from its proposed 2012 revenue requirement, capital components and cost, both Utilities would be squarely in the "Aggressive" risk profile. Gast Reb., NS-PGL Ex. 18.0, 6:112-117. This risk profile combined with the Utilities' "Excellent" business risk profile would translate to an issuer credit rating of BBB, which is lower than the Utilities' current BBB+ issuer rating and just one step above the lowest investment-grade rating of BBB-. *Id.* at 6:118-119; Fetter Reb., NS-PGL Ex. 20.0, 6:116-121. Staff is essentially proposing that the Utilities' credit rating be downgraded, which would increase their risk, capital costs and, ultimately, the rates that their customers must pay. Fetter Reb., NS-PGL Ex. 20.0, 7:140-142. Staff's proposal is contrary to customer interests and should be rejected on those grounds alone.

The Commission would be ill-advised to degrade the Utilities' financial strength and increase their investment risk and the risk of credit rating downgrades, especially in the midst of a highly uncertain economy. The Utilities currently hold relatively strong credit ratings, with BBB+ "issuer" ratings and A/A- "issuance" ratings from S&P and A1 "issuance" ratings from Moody's. NS Ex. 2.4; PGL Ex. 2.4; Gast Reb., NS-PGL Ex. 18.0, 6:119. S&P's rating outlook for the Utilities is "positive," which indicates that they are trending toward credit rating upgrades. Gast Reb., NS-PGL Ex. 18.0, 4:73-74. Adoption of Staff's proposals would put these ratings and outlook at risk.

Aside from its punitive results, Staff's proposal to impute capital structures suffers from numerous methodological and factual flaws, which are described below.

a. The ROE Proxy Group Should Not Be Used to Impute a Utility's Capital Structure

Staff based its proposal on a comparison of the Utilities' historical capital structures and financial performance to those of the Gas Group, all translated to levels of implied financial risk through S&P's financial ratio matrix.[62] The Gas Group was a group of publicly-traded gas utilities compiled by Mr. Moul to serve as a proxy group for the purpose of determining the Utilities' ROEs through mathematical models, not to set the Utilities' capital structures.

Staff's use of the Gas Group to impute capital structure was improper. The reason for a proxy group is not because it is more reliable to study than the utility itself. Rather, the Commission must resort to a proxy group to estimate a utility's cost of equity when the utility's stock is not publicly traded and the market price is therefore unknown. A proxy is not needed to set the utility's capital structure because its capital structures can be derived from its financial statements and its test year capital structure can be reliably forecast. Gast Reb., NS-PGL Ex. 18.0, 10:180-183.

b. In Making Its Comparison to the Gas Group, Staff Misuses the S&P Financial Risk Matrix

Based on its application of the S&P financial risk matrix to their historical financial performance, Staff concluded that the Utilities' "standalone" issuer credit rating is A/A- which is

[62] Ms. Kight-Garlisch claimed that Staff had presented such a comparison in a rate case, but could not cite any specific instances. Tr. 8/31/11, 409:22 – 410:7. The Utilities propounded a data request to Staff seeking identification of any such instances, but Staff has yet to respond, although it has given some preliminary information. If /when Staff provides a response, the Utilities may address it in their reply brief.

higher than their actual issue rating of BBB+ and about the same as the historical average Gas Group issuer rating. Based on this conclusion, Staff asserted that the Utilities' capital structure should be weakened down to the Gas Group's historical level. Kight-Garlisch Dir., Staff Ex. 4.0, 6:93-101. Staff's assertion was based on several misapplications of the S&P matrix.

- S&P admonishes that its credit rating process involves more than its risk matrices, that its "financial benchmarks are guidelines, neither gospel nor guarantees," and that its "assessment of financial risk is not as simplistic as looking at a few ratios." Staff Ex. 13.0, Att. A. But this is precisely what Staff did by using the financial risk matrix as <u>the</u> benchmark by which to set the Utilities' capital structure.
- S&P also makes clear in the "Outlook" section of its company reports that the agency's focus is on current and <u>forecasted</u> financial performance. *E.g.*, NS-PGL Ex. 35.2. Staff's financial risk comparison of the Utilities to the Gas Group was based exclusively on historical data, namely 2010 and a three-year (2008-2010) historical average. Staff's analysis thus ignored the fact that the Utilities' proposed capital structure falls within the range of <u>current</u> capital structures of the Gas Group (Moul Sur., NS-PGL Ex. 36.0, 214-220) and that the Gas Group's <u>forecasted</u> long-term debt-to-permanent capital ratio of 42% is actually <u>lower</u> than the Utilities' current and proposed ratio of 44%. Gast Dir., NS Ex. 2.0, 7:117 – 8:132; PGL Ex. 2.0, 8:135-131; Moul Dir., NS Ex. 3.0, 9:189 – 10:205; PGL Ex. 3.0, 9:189-205.
- As with any model, the results of S&P's financial risk matrix are only as good as the data input to them. Staff's "run" of the matrix in its direct testimony contained significant errors and cannot serve as the basis for a fair comparison of the Utilities and the Gas Group. In purporting to compare <u>actual</u> capital structures, Staff

compared the Utilities' proposed ratemaking capital structure, which contains no short-term debt, to the Gas Group's actual (historical) capital structures, which do contain short-term debt. This mismatch biased Staff's comparison. If an apples-to-apples comparison is made between forecasted actual capital structures excluding short-term debt, the Gas Group's long-term debt-to-permanent capital ratio, and risk, is actually lower than the Utilities'. Gast Reb., NS-PGL Ex. 18.0, 9:161 – 10:174.[63]

- Staff misinterpreted the results of its own financial risk analysis presented on direct. It characterized the Gas Group's implied financial risk as "Significant" based on an average of the companies' credit metrics (Kight-Garlisch Dir., Staff Ex. 4.0, p. 5, Table 1), but this was not accurate. S&P considers five of the eight Gas Group companies to have "Intermediate" financial risk, and only three to have "Significant" financial risk. Gast Sur., NS-PGL Ex. 35.0, 6:130-133. Properly characterized, both the Gas Group and the Utilities have "Intermediate" financial risk.
- On rebuttal, Staff presented a different comparison based on the S&P matrix. This time, Staff purported to base the S&P financial risk ratios and implied risk levels on the Staff revenue requirements. This comparison showed the Utilities with "Intermediate" risk at their proposed capital structure and with "Significant" risk at Staff's proposed capital structure. Kight-Garlisch Reb., Staff Ex. 13.0, 6 (Table 1). Staff's analysis is invalid, however, because the capital components and costs that it used for the comparison were inconsistent with the capital components and costs that Staff used to develop its revenue requirements. If the capital components and costs

[63] In addition, Staff initially excluded Goodwill from the Gas Group capital structures, contrary to S&P's practice. Gast Reb., NS-PGL Ex. 18.0, 9:150-160. Staff corrected this error on rebuttal. Staff Ex. 13.5.

that Staff used to calculate the Utilities' revenue requirements were used in the comparison, then the Utilities would fall into the "Aggressive" financial risk profile, which would not support the Utilities' current credit ratings. Gast Reb., NS-PGL Ex. 18.0, 6:110-122.

- As shown in Section VI.B.1. of this Initial Brief, Staff's imputed capital structure for both Utilities erroneously included capital structures that contain short-term debt. As shown in Section VI.C., Staff's imputed capital structure for Peoples Gas included $51 million in fictitious long-term debt. If these errors are corrected, the resulting capital ratios (about 56% equity, about 44% debt) were extremely close to the Utilities' proposed capital structure. *Id.* at 7:132-142 and p. 8 (table).

c. If the Commission Adopts Staff's Imputed Capital Structures, It Must Adjust the Utilities' ROEs Upward

In the Utilities' last two rate cases, Staff performed a "financial risk adjustment" analysis using the S&P financial risk matrix to support adjustments to the Utilities' ROEs. *Peoples 2009*, p. 105; *Peoples 2007*, pp. 80-81. Staff's theory works in both directions. If the application of the S&P matrix to the Utilities' based on their test year revenue requirements implied a lower credit ratings than the "average" credit rating of the Gas Group, then the Utilities' cost of equity should be adjusted upward to bring it into line with the Gas Group's financial risk level.

As shown above, proper application of the S&P matrix to the Staff revenue requirements would translate to an "Aggressive" financial risk profile for each of the Utilities. Combining that profile with the Utilities' "Excellent" business risk profile would yield a BBB credit rating, which is lower than the Utilities' current BBB+ rating. Using Staff's financial risk adjustment methodology from the Utilities' last two rate cases, the increased financial risk associated with the difference between the two ratings would require an increase in the Utilities' authorized ROE by 23 basis points. Gast Reb., NS-PGL Ex. 18.0, 6:123 – 7:131. Staff did not question this adjustment in testimony, and therefore has no record basis to do so in its briefs.

Accordingly, if the Commission adopts Staff's proposed capital structures, the Commission should make this adjustment to the Utilities' ROEs.

C. Cost of Long-Term Debt (Both Utilities)

The Utilities' proposed cost of long-term debt is reasonable because it is comprised exclusively of existing debt issuances and those that are forecast for the test year. North Shore's embedded cost of long-term debt for 2012 is 5.50%. NS Ex. 2.2. Peoples Gas' embedded cost of long-term debt of 2012 is 4.62%. NS-PGL Ex. 35.3P.

The only remaining issue regarding the Utilities' cost of debt in the test year is whether the calculation of Peoples Gas' cost of long-term debt should include debt that does not exist.[64] Of course, it should not.

Staff agreed to remove Peoples Gas' Series OO long-term debt from its capital structure because the debt was scheduled to be retired this year. Kight-Garlisch Reb., Staff Ex. 13.0, 2:35-37. Series OO was in fact retired on August 18, 2011. Gast Sur., NS-PGL Ex. 35.0, 8:155-156.

Peoples Gas' Series PP long-term debt was retired in 2008. *Id.* at 8:161-162. Staff nonetheless maintained that this debt should remain in Peoples Gas' long-term debt cost calculation unless and until "the Commission enters an Order in Docket No. 11-0476 approving the purchase of the tax-exempt securities backed by Series PP." Kight-Garlisch Reb., Staff Ex. 13.0, 2:37-39. Peoples Gas did not need Commission approval to retire the Series PP bonds

[64] Peoples Gas objected to Staff's reliance on a historical spot-day rate from May 2011 to forecast the interest rate on the Utility's forecasted May 2012 long-term debt issue. Gast Reb., NS-PGL Ex. 18.0, 14:261 – 15:283; Gast Sur., NS-PGL Ex. 35.0, 9:185 – 10:206. But Peoples Gas accepted Staff's rate because it is very close to current forecasted interest rates for the first quarter of 2012. Gast Sur., NS-PGL Ex. 35.0, 10:207-211.

and they have been retired. It is merely the "investment" (holding open the option of issuing tax-exempt debt in the future) that is awaiting Commission approval. Gast Sur., NS-PGL Ex. 35.0, 8:165-170.

The Series PP long-term debt does not exist. Including Series PP in Peoples Gas' long-term debt balances and costs for a 2012 test year would create an arbitrary disconnect between actual and forecasted long-term debt balances and related costs. Staff's adjustment in this regard should be rejected.

D. Cost of Short-Term Debt

As discussed above in Section VI.B.3 of this Initial Brief, no short-term debt should be imputed to the Utilities' capital structures. However, the Utilities do not dispute Staff's estimates of short-term debt cost. *See* Kight-Garlisch Dir., Staff Ex. 4.0, 14:252 – 15:274.

E. Cost of Common Equity (Both Utilities)

1. Proxy Group Analysis

a. The Gas Group Used By All Parties to Determine the Utilities' ROEs Has Lower Risk than the Utilities

Because the Utilities' stock is not publicly traded, the mathematical cost of equity models must be applied to a proxy group of publicly-traded companies with an investment risk profile similar to the Utilities. Moul Dir., NS Ex. 3.0 REV & PGL Ex. 3.0 REV, 3:52-59. As in the Utilities' last two rate cases, Mr. Moul assembled a group of publicly-traded natural gas utilities to serve as the "Gas Group" by conducting a "fundamental risk analysis" to determine whether the investment risk of the Gas Group and the Utilities was similar. Moul Dir., NS Ex. 3.0 REV, 6:131 – 12:247; PGL Ex. 3.0 REV, 6:131 – 12:248; NS Exs. 3.2 – 3.5; PGL Exs. 3.2 – 3.5. Based on this thorough analysis, Mr. Moul concluded that the Gas Group had lower overall investment risk than the Utilities. Moul Dir., NS Ex. 3.0 REV, 12:248 – 13:259; PGL Ex. 3.0

REV, 12:249 – 13:259. But he found it impractical to come up with a group with similar risk because of the very small number of candidate gas utilities. Therefore, he admonished that the ROEs set for the Utilities should recognize their "higher risk characteristics" than are reflected in the costs of equity calculated with the mathematical models. Moul Dir., NS Ex. 3.0 REV & PGL Ex. 3.0 REV, 13:259-264.

The ROE witnesses for Staff and GCI relied on Mr. Moul's Gas Group for their analysis and proposals. Mr. McNally testified that he "adopted the same group of gas utility companies that Companies' witness Moul used in his estimate of the return on common equity for North Shore and Peoples Gas. <u>I believe that Mr. Moul's sample companies provide reasonable proxies for the operating risk of North Shore and Peoples Gas</u>." McNally Dir., Staff Ex. 5.0, 2:39-42 (emphasis added). Mr. Thomas questioned Mr. Moul's finding that all companies in the Gas Group had some form of decoupling but offered no evidence to contradict it, and relied on Mr. Moul's models to derive GCI's ROE proposal. Thomas Dir., GCI Ex. 5.0, 3:50-65, 9:182-191.

Mr. McNally, however, changed his position on rebuttal. Purportedly in response to Mr. Moul's observations in his rebuttal that Mr. McNally "failed to recognize the higher risk of the Utilities in making his recommendation," and that "contributes to the serious underestimation of their costs of equity by him," Mr. McNally presented a tardy response to the proxy group analysis that Mr. Moul presented in his direct testimony. Moul Reb., NS-PGL Ex. 19.0 REV, 10:203-205. Now Mr. McNally claimed that Mr. Moul's analysis was "distorted" by refunds the Utilities paid in 2006 and 2007. McNally Reb., Staff Ex. 14.0, 28:605 – 32:695.

It is Mr. McNally's analysis that is distorted. He grossly overstates the impact of the 2006 and 2007 refunds. The impact is relatively small as measured by the coefficients of variation of the Utilities' actual returns. Moul Sur., NS-PGL Ex. 36.0, 8:167 – 9:188. More important, Mr. McNally's new analysis ignored the significant increase in the Utilities' risk that Staff's proposed imputed capital structures would cause. Moul Sur., NS-PGL Ex. 36.0, 10:207-220.

b. Staff's Principal Components Analysis Fails to Support a Finding that Peoples Gas' Investment Risk Is Lower than the Gas Group's Investment Risk

Staff's abrupt change in its position on the comparability of the Gas Group and the Utilities was also based on a "principal components analysis"[65] that Staff stated it performed on twelve operational and financial ratios for a new group of 95 utility companies, all in the period between the Utilities' and Staff's rebuttal filings. McNally, Tr. 8/31/11, 528:20 – 529:12, 534:3-10; McNally Reb., Staff Ex. 14.0, 33:696 – 36:772. This new analysis was not proper rebuttal, as Mr. Moul presented his conclusion that the Utilities have greater investment risk than the Gas Group on direct and Staff's production of this new analysis on rebuttal gave the Utilities only one week to respond before their surrebuttal was due. The analysis was based on a Staff-created computer program and data that Staff has not produced to this day, and was laden with numerous methodological and factual errors. Moreover, Staff's analysis failed to comply with numerous ground rules for this type of analysis laid out in the "textbook" issued by SAS, the

[65] The purpose of a principal components analysis is to take a situation where there are many data inputs or variables (here, the ratios) gathered for a certain population (here, the 95 utility companies), and determine if the differences shown by those variables for the members of that population can be explained by a smaller set of artificial variables – called "principal components" or "factors." Each "principal component" or "factor" seeks to capture the explanatory nature for a subset of those variables that happen to be correlated with each other so as to be describing the same concept, attribute or behavior of the population at issue. *See* McNally Tr. 8/31/11, 579:22 – 580:13; NS-PGL Cross Ex. 3, pp. 2-10. The starting point or purpose of performing the principal components analysis is to determine if there is a smaller number of such factors, and if so, how many, that explain a meaningful amount of the variance seen in the population so that the analyst can work with a smaller set of factors rather than the larger group of original variables. *See* NS-PGL Cross Ex. 3, pp. 1-2, 7-8, 21-22.

author of the software Staff used.[66] The following is a summary of the problems existing with Staff's principal components analysis:

- Failure to Disclose Underlying Equations and Data. Cross-examination revealed the following items that Staff should have disclosed in its work papers in order or in response to the Utilities' data requests for the Utilities to evaluate and test the validity and relevance of its results:
  - the equations and data Staff used to calculate its twelve ratios used as variables in the analysis (McNally, Tr. 8/31/2011, 539:1 – 540:10, 545:4 - 548:3);
  - how the data used in the ratios was averaged over the three-year period used by Staff (*id*. at 541:4-15, 543:10-18);
  - the underlying data pulled by Staff's SAS statistical software to be used in the calculations (*id*. at 541:20 – 542:4, 544:5 – 545:14); and
  - whether the data was all calendar year or fiscal year, or a combination of both (*id*. at 554:16 – 555:6).
- Failure to Disclose the Underlying SAS Instructions. Staff ran its principal components analysis using a set of instructions it created – a program – to tell the SAS software how to run the analysis. *See id*. at 539:1 – 540:10, 545:4 – 548:3, 566:1 – 567:3, 590:4-12, 597:5 – 598:18. Staff did not disclose this set of instructions. *Id*. at 567:4 – 569:1. Without knowing these instructions, it is impossible to determine how the analysis was performed.

[66] Staff's witness who performed the principal components analysis conceded that he is not a statistician and does not have any formal training in performing a principal components analysis. McNally , Tr. 8/31/2011, 556:22 – 558:5, 559:5-11. Rather, he stated that he learned how to run a principal components analysis from "on-the-job training" and relies upon the SAS statistical software and a "textbook" published by SAS to perform the statistical analysis. *Id*. at 556:22 - 557:3, 559:12-20; NS-PGL Cross Ex. 3.

- Inclusion of Different Types of Companies into the Sample Population than Used in Mr. Moul's Analysis. Staff produced this analysis as a response to Mr. Moul's proxy analysis. Yet, Staff included ten water utilities and six limited partnerships in its sample. *Id*. at 572:3 – 573:3, 574:17 – 575:13. Staff conceded that the inclusion of these sixteen different types of entities may have impacted the results of its analysis. *Id*. at 574:13-16, 577:7-11.

- Predetermined Number of Factors. The initial purpose of running a principal components analysis is to see whether a sample with data for many variables can be meaningfully explained by a fewer number of artificial variable called "principal components" or "factors," and, if so, by how many. NS-PGL Cross Ex. 3 at 1-2, 7-8, 21-22. Staff, however, predetermined the number of factors it would keep by instructing the SAS software to keep only the four factors discussed in Mr. McNally's rebuttal before the analysis was even run. McNally Tr. 8/31/2011, 590:4-12.[67] As Staff conceded, keeping even a fifth factor would have reduced the overall amount of unexplained data by nearly half. *Id*. at 595:10-13.

- Failure to Use a Graph to Perform a "Scree Test". While Mr. McNally claimed he used what is known as a "scree test" to validate his decision to use only four factors, he admitted that he did not perform this test using a visual graph plotting the results of the analysis as clearly required in the SAS textbook. *Id*. at 589:12-20, 590:1-3, 591:2-5; NS-PGL Cross Ex. 3 at 16, 23-25.

[67] While Staff's witness previously had testified that he only ran the principal components analysis one time and did not run other versions of it with different assumptions (*see* McNally, Tr. 8/31/2011, 534:11-16, 574:8-12), in defending this decision, he contradicted himself by stating he thought he ran the analysis with instructions to keep three or five factors to see how that impacted the results, but he did not produce those and could not remember the results. *Id*. at 592:18 – 593:7

- Inadequate Sample Size. The SAS textbook clearly requires that in order for a principal components analysis "[t]o obtain reliable results," the data sample used should always have a minimum of at least 100 subjects, and that this minimum often needs to be even higher. NS-PGL Cross Ex. 3. Staff admitted that its sample size of 95 companies failed to meet this requirement. McNally, Tr. 8/31/2011, 580:14 – 581:19. Moreover, if the 16 water utilities and limited liability partnerships were excluded as they should have been, Staff's sample would only have included 79 companies.[68]

- Failure to Meet SAS' Interpretability Criteria. The SAS textbook states that for a principal components analysis to be considered to have produced "overall results" that are "satisfactory," certain interpretability criteria must be met. NS-PGL Cross Ex. 3 at 26-27, 30. One of those criteria is that each factor kept in the analysis has at least three variables that "load" onto it following the procedure set forth in the SAS textbook. *Id*. at 12, 29-30.[69] The SAS textbook clarifies that this three variables per factor guideline "should be viewed as an absolute minimum" and a "rock-bottom lower bound" for the results of a principal components analysis to be considered satisfactory. *Id*. at 12 (emphasis added). As shown by its output, two of the factors in Staff's analysis failed to meet this "absolute

[68] Indeed, in response to questions regarding the inclusion of the water utilities and limited partnership companies, Staff raised the concern of "not having enough observations" if those companies were excluded from the analysis. McNally Tr. 8/31/11, 577:12 – 578:6. Thus, it appears that Staff may have included these entities despite their differences from the companies used in Mr. Moul's analysis and from the Utilities in an effort to get its sample size as close to the SAS' minimum population requirement as possible, without regard to how the inclusion of those companies may have impacted the results.

[69] Part of performing a proper principal components analysis requires the analyst do determine which variables align with, or "load on," each of the factors retained in the first part of running the analysis. NS-PGL Cross Ex. 3 at 12, 26-27, 30.

minimum" of at least three variables loading on each factor. McNally Tr. 8/31/11, 599:5 – 603:4; NS-PGL Cross Ex. 3 at 29-30; NS-PGL Cross Ex. 5 at 28.

In the only judicial decision found that discusses the admissibility and/or weight to be given a principal components analysis, *Attorney General of Oklahoma v. Tyson Foods, Inc.*, 565 F.3d 769 (10th Cir. 2009), the court held that it was appropriate to discount the proffered analysis as insufficiently reliable. In *Tyson Foods*, an expert witness introduced a principal components analysis purporting to analyze a large sample of data to identify poultry litter contamination in the Illinois River Watershed. In affirming the district court's decision that the analysis was insufficiently reliable, the Tenth Circuit relied upon the fact that in performing his principal components analysis, the expert was required to make discretionary decisions about which data to enter into his calculations and the methodology to be used, and that those discretionary decisions had not been "tested or peer reviewed." 565 F.3d at 781. Staff's principal components analysis likewise was the product of many discretionary decisions made regarding data inputs and methodology, without any independent peer review to support those decisions.

For these reasons, the Utilities are hopeful that Staff will conclude that the use of a principal components analysis under the circumstances of this proceeding was not proper, and abandon it as a basis for its recommendations in this case. If not, for the reasons summarized above, the Commission should strike or disregard Staff's late analysis and change of position on the comparability of the Utilities to the Gas Group.

c. <u>Proxy Group Analysis Conclusion</u>

Mr. Moul's consistent methodology and sound conclusion that the Gas Group has lower risk than the Utilities should guide the Commission's evaluation of the financial models and other evidence pertaining to the Utilities' cost of equity. Staff's late attempt to challenge Mr. Moul's conclusion was unfair and unfounded.

2. The Utilities' ROE Proposal Is Based on Consistent Methodologies and the Same Types of Market Data on Which Investors and Analysts Rely

Mr. Moul is an independent financial and regulatory consultant with 35 years' experience analyzing utility cost of equity. NS Ex. 3.1; PGL Ex. 3.1. He testified and provided the Utilities' proposed ROEs in each of their last two rate cases. He used the same methodologies to estimate the Utilities' cost of equity as did in those prior cases. He based his recommendation on three market-based mathematical models to estimate the Utilities' market cost of equity: Discounted Cash Flow ("DCF"), Capital Asset Pricing ("CAPM") and Risk Premium models. In each case, Mr. Moul developed inputs to the models based on his independent evaluation of historical, current and forecasted information readily available to investors and financial analysts.

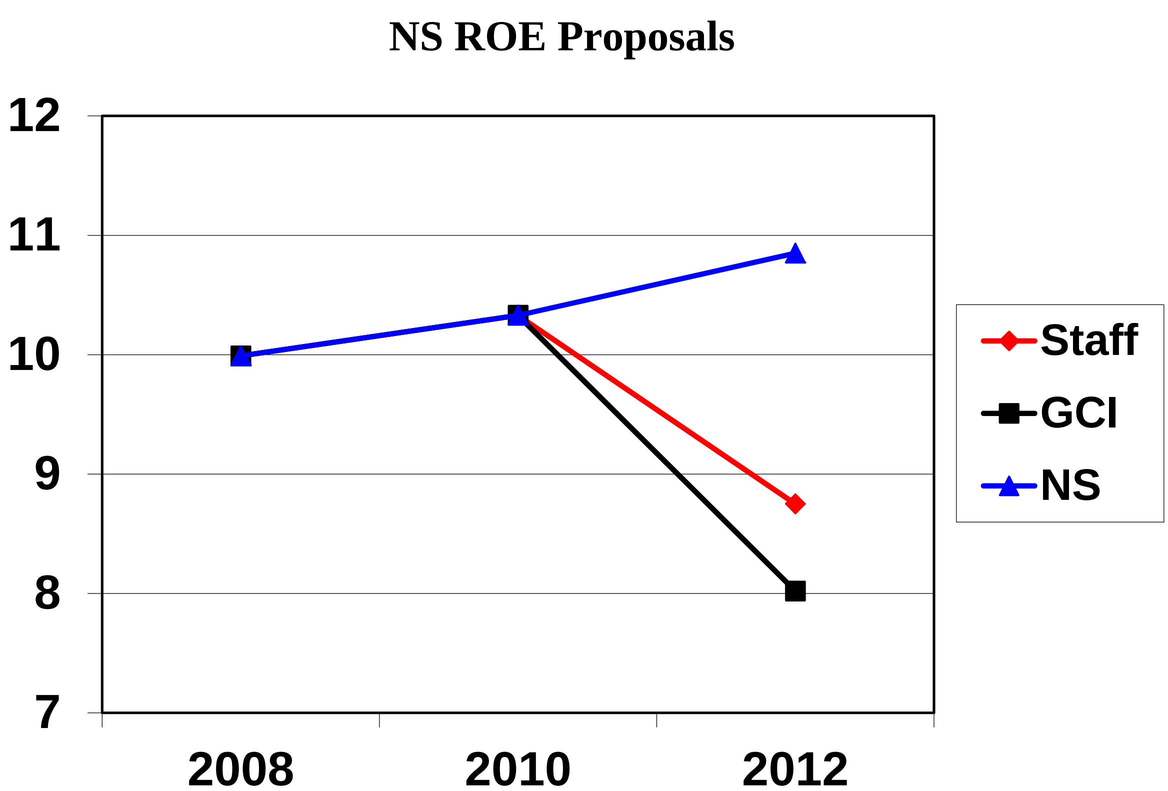
He presented results of these models on direct and updated results on rebuttal. His results were as follows:

Gas Group Financial Model Results

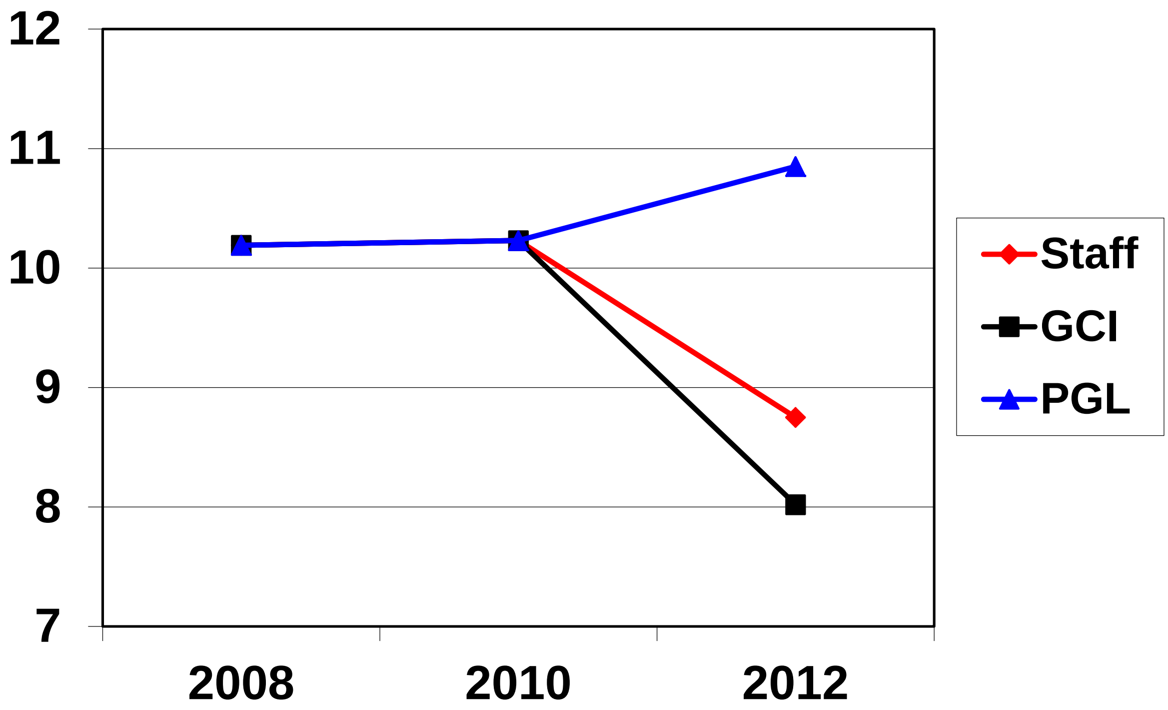
Model	February	July
DCF	9.67%	9.03%
CAPM	11.21%	11.56%
Risk Premium	11.25%	11.25%
Average	10.71%	10.61%

Moul Reb., NS-PGL Ex. 19.0, 7:139-140. Based on these results, and discounting the DCF results for the reasons explained below, Mr. Moul recommended a cost of equity of 10.85% for each Utility, which would represent a modest increase over the Utilities' current ROEs of 10.33% (North Shore) and 10.23% (Peoples Gas).

By contrast, Staff and GCI propose significant decreases of the Utilities' ROEs. Staff proposes 8.75% and the mid-point of GCI's proposed range is only 8.02%. The parties' proposals and the Utilities' 2008 and 2010 authorized ROEs are compared in the following graphs:



PGL ROE Proposals



Staff's and GCI's proposed ROEs are based on inconsistent and flawed methodologies that reflect their opinions of what the Utilities' ROEs <u>should</u> be, and therefore should be rejected in favor of Mr. Moul's model results and recommendation.

a. Staff Has Not Justified its Continued <u>Reliance on Spot Day Stock Prices</u>

As it has in the Utilities' past rate cases, Staff used data from a single day several months ago (May 12, 2011) in its DCF and CAPM models. The single day Staff chose for its models generated a DCF result of only 8.50% and a CAPM result of only 9.20%., each of which is over 100 basis points below the ROEs the Commission set for the Utilities in January 2010.

The Utilities again urge the Commission to reject Staff's use of single-day spot data in its cost equity analyses. The use of such data invites subjectivity and error. Obviously, the day can be selected by the analyst and this can lead to gamesmanship. In addition, the results based on one day's data can be erroneous because there is evidence that short-term inefficiencies exist in stock prices, especially in periods of high volatility. Moul Reb., NS-PGL Ex. 19.0, 11:227 – 12:260.

The Commission rejected Staff's DCF result in the Utilities' 2007 rate cases because it generated "anomalous" results, and the Utilities urge the Commission to do so again in this case. *Peoples 2007*, p. 92. A low result, the Commission instructed, should lead Staff to "check" its results by "the use of an alternative sample date or an average across a six-month, or other, period…." *Id.* In the Utilities' last rate case, the Commission directed that parties relying on spot data make the following showing:

> The Utilities argue that spot data is exposed to inefficiencies from a number of sources and that Staff's reliance on such data without considering what it represents is itself arbitrary. We agree that it would be 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 reasonable combination of both.

Peoples 2009, pp. 125-126.

Staff completely ignored this direction in presenting its extremely low 8.50% DCF result. Staff updated its ROE analysis no less than six times between its direct and rebuttal testimonies and provided none of the required contextual showing, except for noting the extreme stock market volatility during the week of August 8th. McNally Reb., Staff Ex. 14.0, 10, fn. 21. Staff did not disclose the relative stock market volatility around any of the other days it selected, so it apparently expects the Commission to accept at face value that there was nothing anomalous about those other dates.

There is yet another unexplained deviation in Staff's seven spot day DCF analyses. Staff used different sources of growth rates on different days. McNally Reb., Staff Ex. 14.0 at 10, fn. 20. Staff acknowledged the variation but <u>fails to explain why</u>.

There are also problems with Staff's spot day quotes of the risk-free rate for its CAPM model. The quotes were inconsistent with <u>Blue Chip</u> and <u>Global Insight</u> forecasts of Treasury yields, which both indicate such rates increasing in the future beginning in 2012. Moul Reb., NS-PGL Ex. 19.0, 19:375 – 20:391. Even the newer interest rate forecasts that Staff was allowed to introduce through Mr. Moul (dated as late as August 29, 2011, the day the hearing started) were higher than the May 2011 rates Staff relied on. Moul Tr. 8/31/11, 489:16 – 491:13 (5.0% forecast for 30-year Treasury bonds); Staff Cross Ex. 6; *compare* McNally Dir., Staff Ex. 5.0, 10:199-204 (4.42% current yield for 30-year Treasury bonds). The forecast information is by definition a more reliable basis on which to establish the Utilities' rates for a <u>future</u> test year, and Staff's refusal even to consider how data from a single day over four months ago might change in the future is by definition arbitrary.

In summary, the Commission's task is not to set the Utilities' cost of equity for one day in mid-2011, but rather to determine an approximate cost that is representative during the 2012 test year if not a longer period. Staff's use of data from a single day in the past can accomplish that objective only by sheer coincidence. A credible and conscientious analyst should, indeed must, consult the variety of data available to investors and analysts in the real world – historical, current and forecast – to determine whether his or her work has any relevance to the real world. Staff's abject refusal to do so, and the extremely disparate results that its analyses generate, renders Staff's DCF and CAPM analyses unreliable for use in these rate cases.

b. **DCF Results Should Be Discounted <u>or Discarded at this Time</u>**

Mr. Moul demonstrated that unique circumstances at play in today's unsettled economy are causing the DCF model to generate unreliably low measures of the Gas Group's equity cost. Growth prospects for natural gas utilities have eroded significantly due to the economic recession and dividend yields among the Gas Group remain low due to the low interest rate environment. Moul Dir., NS Ex. 3.0 & PGL Ex. 3.0, 5:99-101. But while the Gas Group's growth rates have fallen 32% on average since the Utilities' last rate cases, their stock prices have increased by 36% on average. Growth in stock prices while growth rates are falling is an anomalous situation that cannot be sustained. Moul Reb., NS-PGL Ex. 19.0, 16:326 – 17:343.

Mr. Moul tested his conclusion by running his models on a gas and electric utility combination proxy group (the "Combination Group") and found that the DCF yielded a cost of equity for that group of 11.22% in February and of 10.48% in July:

Combination Group Financial Model Results

Model	February	July
DCF	11.22	10.48%
CAPM	11.45%	11.71%
Risk Premium	11.25%	11.25%
Average	11.31%	11.15%

Id. at 7:139-140. In each case, the Combination Group DCF results are higher and much closer to the CAPM and Risk Premium results for the Gas Group. Moul Dir., NS Ex. 3.0, 5:95-96, 5:107 – 6:118; Moul Reb., NS-PGL Ex. 19.0, 9:139-140.

Another indication that the DCF model, especially Staff's version of it, is not currently generating reliable results is the large differences between the Utility and Staff DCF results in the instant cases and those in the Utilities' last rate cases. The following table compares the unadjusted constant-growth DCF results between the two cases, and measures the differences by basis points ("BP"):

Utility/Staff DCF Results, 2009 and 2011 Rate Cases

	2009	2011	Difference
Utility	10.67%	9.16%	151 BP
Staff	11.76	8.50%	326 BP

See Peoples 2009, p. 126; Moul Dir., NS Ex. 3.0, 29:638-639; McNally Dir., Staff Ex. 5.0, 6:119-120. Whereas Mr. Moul finds his own unadjusted DCF result to be unreasonably low, there is simply no explaining the 326-basis point drop in Staff's results in two years' time. Staff's results are too disparate to represent the products of a valid model.

These results confirm Mr. Moul's opinion that contradictory and anomalous trends unique to the natural gas industry – stock price growth and growth rate decline – make the DCF model currently an unreliable measure of equity cost for the Gas Group.

c. Mr. Moul's DCF Growth Rates Are Sustainable

Mr. McNally quibbles with the earnings growth rate sources Mr. Moul chose to use in this case (McNally Dir., Staff Ex. 5.0, 27:520 – 29:570), but as shown above, Mr. McNally reserves to himself the same discretion to pick growth rate sources to suit his purposes without any explanation at all.

Mr. McNally questioned Mr. Moul's selection of a Morningstar growth rate as one of four sources Mr. Moul consulted, arguing that it was "dubious for the Gas Group." *Id.* at 29:571 – 30:590. Mr. McNally had only a specious response to Mr. Moul's demonstration that the Morningstar rate was "entirely consistent with the (b x r) plus (s x v) formulation of sustainable growth. Moul Reb., NS-PGL Ex. 19.0, 18:361-373. Mr. McNally asserted that Mr. Moul erroneously assumed that all new stock is issued at market price, speculated that stock issued as part of employee compensation was not issued at market, and called Mr. Moul's analysis "unreliable." McNally Reb., Staff Ex. 14.0, 17:354-366.

It was Mr. McNally who was mistaken. Stock and stock options issued as part of compensation are issued at market price. Gast Sur., NS-PGL Ex. 35.0, 10:213 – 11:225. But if Mr. McNally was right, he contradicted Staff's long-held position that current market price is the sole determinant of the cost of equity, which is the basis for Staff's use of spot data in its DCF and CAPM models. Moul Sur., NS-PGL Ex. 36.0, 6:111-117. In any event, Mr. McNally's point is purely theoretical because Mr. Moul's growth rate analysis reflected only stock shares expected to be issued and did not include stock options that are not subsequently exercised in the future. *Id.* at 6:118-124; NS-PGL Ex. 19.12.

d. Mr. Moul's Leverage Adjustment Is Necessary to Reflect the *Market's* Evaluation of Risk Associated with Capital Structure

The Utilities acknowledge that the Commission has twice rejected Mr. Moul's "leverage adjustment," which is intended to correct the mismatch between a cost of equity derived from the market's evaluation of a utility's risk associated with its capital structure valued at market to the higher risk associated with the utility's capital structure valued at book value. At market value, the utility's capital structure has proportionally more equity and less debt, and therefore much less risk than the utility's capital structure valued at book.

Staff continues to oppose the adjustment, with such epithets as "absurd," "obviously untrue," and "unequivocally false." But Staff does not – indeed cannot – challenge the rock solid principle on which it is based, namely that a company's risk and cost of equity based on a market value capital structure with a higher equity ratio are lower than the company's risk and cost of equity based on a book value capital structure with a lower equity ratio. Moul Dir., NS Ex. 3.0, 24:536 – 26:572. Indeed, Mr. McNally agreed on cross examination that a company with an equity ratio of 55% "will have a higher degree of financial risk than if the company had a 66% equity ratio." McNally Tr. 8/31/11, 518:5-7.

Staff repeatedly argued that "a company cannot be riskier than itself at any point in time." McNally, Tr. 8/31/11, 518:7-8; *see also* McNally Dir., Staff Ex. 5.0, 31:618-619; McNally Reb., Staff Ex. 14.0, 428-431. This argument misses the point entirely. It may be true, as Mr. McNally asserted, that "[t]he intrinsic risk level of a given company does not change simply because the manner in which it is measured has changed," but the real point is that "capital structure ratios are … indicators of financial risk." McNally Dir., Staff Ex. 5.0, 31:618-619, 622-623. Regardless of the company's actual "intrinsic" level of financial risk, its capital structure is the basis for the market's perception of the company's financial risk level and the market prices the company's capital accordingly.

The following example demonstrates why the leverage adjustment is necessary. Assume a utility with $1000 in total market value capitalization. At market value, its capital structure is $600 equity and $400 debt. Based on book valuation, however, the utility's equity has only $500 in value, so its book value capital structure is $500 equity and $400 debt. The utility's market cost of equity based on its market value capital structure is 10%, implying that the utility's total dollar cost of equity is $60. If the utility's cost of equity was instead based on its book value capital structure, then all other things equal it would be 12%, the rate needed to generate $60 of earnings on $500 of equity. Thus, without a leverage adjustment, and again holding all else equal, the utility cannot earn its total cost of equity.

Mr. McNally had it almost right when he testified as follows:

> The application of the market required return to the book value rate base simply takes the return investors demand to earn from a dollar invested in the common equity of a company, given the amount of risk in the common equity of that company and the current price of risk, and applies it to the number of common equity dollars invested in the rate base of the [company].

McNally Reb., Staff Ex. 14.0, 23:494-499 (emphasis added). Mr. McNally failed to acknowledge that a utility's market required return is based on a market value capital structure, which has more common equity dollars in it than the utility's book value capital structure. Thus the market required return applied to fewer dollars will yield less total dollars of earnings to cover the utility's total dollar cost of equity. As Mr. Moul made clear, "In every instance the scale [to measure financial risk, in reference to Mr. McNally's temperature analogy] has been uniform, and only the input values (i.e., dollar amounts) vary according to whether market value amounts of debt, preferred stock and common equity are employed, or if the corresponding book value amounts are used in the calculations. Mr. McNally's analogy is entirely off-point, as is the criticism he bases on that analogy." Moul Sur., NS-PGL Ex. 36.0, 7:131-135 (emphasis added).

Thus, the problem that is solved by the leverage adjustment has nothing to do with varying levels of "intrinsic" financial risk, as Staff asserts. The leverage adjustment simply corrects the utility's under-recovery of its total dollar cost of equity if the utility's market cost of equity based on its market value capital structure is applied to its book value capital structure.

e. Staff's CAPM Betas Are Biased on the Low Side

There are numerous published sources that provide calculated betas on firms, sources that are readily available to and relied on by investors and analysts. Staff relied on two of them, Value Line and Zacks. McNally Dir., Staff Ex. 5.0, 13:251-253. But these were not sufficient for Staff's purposes. Staff also calculated its own "regression beta" and then "adjusted the raw beta to produce a more accurate forward-looking beta estimate." *Id.* at 14:266 – 16:293.

Given that the object of the exercise is to determine the investor required return on equity, separately calculated betas are not necessary as no investor could possibly rely on them. More important, in Mr. Moul's experience there is a downward bias in Staff's betas, "which have always been lower than Value Line betas." Moul Reb., NS-PGL Ex. 19.0, 20:395-407. In his rebuttal, Mr. McNally did not dispute Mr. Moul's characterization.

The Commission should not base its cost of equity decision on models that include biased data and should for this reason reject Staff's CAPM ROE estimate.

f. GCI's ROE Position Lacks Credibility

For all of its claims to be the Commission's only objective source of cost of equity analysis, GCI's position on the Utilities' ROEs should prove otherwise. Although GCI started with Mr. Moul's models, every adjustment it made to them had the effect of reducing their results. On rebuttal, GCI reduced its proposed ROE range to 7.09% - 8.94%, and suggests that it should be even lower "given the bias that remains in Mr. Moul's analysis." Thomas Reb., GCI Ex. 10.0, 15 (table); Thomas Dir., GCI Ex. 5.0, 34:750-751. Any party taking the position that the Utilities' ROEs should be reduced by over 300 basis points cannot be taken seriously. GCI's "Moul adjusted" ROE proposal is flawed in the following ways:

- Mr. Thomas deleted Mr. Moul's leverage adjustment from his DCF model. Thomas Dir., GCI Ex. 5.0, 21:464-470.
- Mr. Thomas deleted Mr. Moul's size adjustment from his CAPM analysis. *Id.* at 29 (Table 3).

- Mr. Thomas replaced Mr. Moul's CAPM beta with lower betas to develop two alternative and lower results, 7.22% and 8.14%. *Id.* at 33 (Table 4).

F. Weighted Average Cost of Capital

1. Peoples Gas

The Commission should include in Peoples Gas' 2012 rates an overall ROR of 8.11% comprised of a capital structure of 56% equity and 44% long-term debt, a cost of equity of 10.85% and a cost of long-term debt of 4.62%.

2. North Shore

The Commission should include in North Shore's 2012 rates an overall ROR of 8.50% comprised of a capital structure of 56% equity and 44% long-term debt, a cost of equity of 10.85% and a cost of long-term debt of 5.51%.

VII. WEATHER NORMALIZATION – AVERAGING PERIOD (Uncontested)

The Utilities proposed using the average of 12 years of weather data, ending in 2009. Kuse Dir., PGL Ex. 4.0, 10:170-172; Kuse Dir., NS Ex. 4.0, 10:168-170. No witness disagreed.

VIII. RIDERS – NON-TRANSPORTATION

A. Riders UEA and UEA-GC

To comply with a Commission-approved Stipulation in Docket Nos. 09-0419/09-0420 (cons.), the Utilities each proposed Rider UEA-GC, Uncollectible Expense Adjustment-Gas Costs. The proposed rider is consistent with the Stipulation's requirement that the rider be "similar to" an uncollectible gas cost rider that the Utilities had proposed, but withdrawn, in their 2009 rate cases. Grace Sur., NS-PGL Ex. 45.0, 27:562-576. This rider would recover from customers gas cost related Account 904, Uncollectible Accounts Expense, through a factor applied to customers' bills, rather than base rates. The Utilities also proposed changes to

Rider UEA, Uncollectible Expense Adjustment, to coordinate with Rider UEA-GC. Grace Dir., NS Ex. 12.0 REV, 52:1161-1171, 53:1195-1198; PGL Ex. 12.0 REV, 55:1224-1234; NS-PGL Ex. 28.0, 36:778-794; NS-PGL Ex. 28.2. The factors applied to the gas charge portion of sales customers' bills are derived from the allocation of Account 904 costs for each service classification in the embedded cost of service studies ("ECOSSs"). If the Commission approves the rider, amounts that would be recovered under the rider would need to be removed from the Utilities' revenue requirements. Grace Dir., NS Ex. 12.0 REV, 52:1171 - 53:1186; PGL Ex. 12.0 REV, 55:1235-56:1249.

The Utilities also proposed to eliminate from Rider UEA, effective June 1, 2013, the Incremental Transportation Uncollectible Amount ("ITUA"), which recovers or refunds incremental Account 904 amounts related to transportation service. Eliminating the ITUA is appropriate as many transportation accounts are aggregated into pools, and the Utilities receive credit assurances. Grace Dir., NS Ex. 12.0 REV, 53:1201-54:1225; PGL Ex. 12.0 REV, 56:1264-57:1288.

Staff witness Mr. Kahle proposed revisions to the riders and also recommended the net write-off method to determine uncollectibles expense. Kahle Dir., Staff Ex. 1.0, 20:438-24:536. In response to Mr. Kahle, the Utilities revised Riders UEA and UEA-GC to address his concerns. Grace Reb., NS-PGL Ex. 28.0, 35:756 - 38:821; NS-PGL Exs. 28.2, 28.3.

The Utilities opposed changing to a net write-off method and noted that, if the Commission required the change, Riders UEA and UEA-GC would need extensive revisions that Staff did not thoroughly address. The current percentage of revenue method is reflected throughout both riders. Grace Reb., NS-PGL Ex. 28.0, 38:824-833; Grace Sur., NS-PGL

Ex. 45.0, 26:549-558. The Utilities' opposition to the net write-off method is addressed in Section V.C.5, *supra*.

Riders UEA and UEA-GC, as revised by the Utilities in their rebuttal testimony, should be approved, including the percentage of revenue method.

B. <u>Rider VBA</u>

The Commission approved Rider VBA, Volume Balancing Adjustment, as a four-year pilot program in the 2007 rate case. Rider VBA applies to Service Classification ("S.C.") Nos. 1 and 2 and is a symmetrical full decoupling mechanism. The Commission concluded that "a general rate case needs to be filed if Rider VBA is to become effective upon the conclusion of the pilot program." *Peoples 2007*, p. 152. In this case, the Utilities proposed to implement Rider VBA on a permanent basis, and they proposed revisions to the rider both in their direct testimony and in response to Staff witness Ms. Ebrey. Over the pilot period, Rider VBA operated effectively to provide refunds to customers when distribution revenues (Actual Margin) per customer exceeded Commission-approved per customer levels (Rate Case Margin) and charges to customers when Actual Margin was less than Rate Case Margin. Grace Dir., NS Ex. 12.0 REV, 48:1088-1090, 50:1124-1130; PGL Ex. 12.0 REV, 51:1151-1153, 53:1187-1194.

Rider VBA remains appropriate because, under the Utilities' rate design proposals, a substantial amount of fixed costs (30% for North Shore and 36% for Peoples Gas) would continue to be recovered through variable charges. This level of recovery: (1) is not aligned with the nature of the Utilities' fixed cost delivery service; (2) ensures that the Utilities either under or over recover their Commission approved revenue requirements; (3) ensures that customers will pay more or less than their share of Commission-approved distribution costs; and (4) is far more than the 20% recovery that the Commission approved for Ameren and Nicor.[70] Grace Dir., NS Ex. 12.0 REV, 49:1092-1099; PGL Ex. 12.0 REV, 52:1155-1162.

From May 2008 through August 2011, Peoples Gas refunded about $22.9 million and North Shore refunded about $4.7 million to S.C. Nos. 1 and 2 customers. Grace Reb., NS-PGL Ex. 28.0, 30:661-663. Absent the rider, customers would have paid more than their share of the Commission-approved distribution revenues. Grace Dir., NS Ex. 12.0 REV, 50:1119-1124; PGL Ex. 12.0 REV, 53:1182-1187.

The Utilities implemented the rider with monthly adjustments and annual reconciliation amounts. The intent was to provide near real-time adjustments to customers. The Utilities proposed annual adjustments in this case to smooth out the monthly adjustments and streamline the filing process. The Utilities detailed various filings they would need to make in 2012 and 2013 to transition from the monthly to the annual mechanism. The Percentage of Fixed Costs would be set at 100% to reflect the Utilities' test year costs, which are all fixed. Grace Dir., NS Ex. 12.0 REV, 49:1102-1104, 50:1134-51:1159; PGL Ex. 12.0 REV, 52:1165-1167, 53:1197 - 54:1222.

Staff witness Dr. Brightwell supported making Rider VBA permanent. Brightwell Dir., Staff Ex. 6.0, 4:66-72. Although the Utilities did not agree with all of Dr. Brightwell's reasoning for preferring decoupling to a straight fixed variable ("SFV") rate design, they concur with his conclusion that making Rider VBA permanent is appropriate. Staff witness Ms. Ebrey proposed several revisions to the rider, most of which the Utilities accepted.

The proposed changes that the Utilities accepted, with minor modifications that Ms. Ebrey found acceptable, are:

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70 *In re Central Illinois Light Co., Central Illinois Public Serv. Co. and Illinois Power Co.*, ICC Docket Nos. 07-0588, 07-0589 and 07-0590 (Cons.) (Order, Sept. 24, 2008), p. 237; *In re Northern Illinois Gas Company d/b/a Nicor Gas Company*, ICC Docket No. 08-0363 (Order Mar. 25, 2009), p. 91.

- replacing the word "margin" throughout the tariff with the word "revenue." Ebrey Dir., Staff Ex. 3.0, 35:806-37:838. The Utilities agreed to this change if the definitions clearly link the wording to the approved revenue requirement. Grace Reb., NS-PGL Ex. 28.0, 19:414-20:443. Ms. Ebrey did not oppose the Utilities' proposed language. Ebrey Reb., Staff Ex. 12.0, 26:465-467.
- modifying the annual internal audit requirements. Ebrey Dir., Staff Ex. 3.0, 42:977-43:1005; Grace Reb., NS-PGL Ex. 28.0, 24:520-26:563; NS-PGL Ex. 45.5; Ebrey Reb., Staff Ex. 12.0, 26:468.
- requiring a compliance filing as new values to be used in the calculations are determined in a rate case proceeding. Ebrey Dir., Staff Ex. 3.0, 43:1010-1020; Grace Reb., NS-PGL Ex. 28.0, 26:567-574; NS-PGL Ex. 45.5; Ebrey Reb., Staff Ex. 12.0, 26:469-471.

For the other proposal, the Utilities offered an alternative that would preserve Rider VBA's function of ensuring that the Utilities neither over- nor under-recover their approved revenue requirements. Ms. Ebrey proposed to change the calculations so that "total revenues" rather than "per customer revenues" are used to determine adjustments. Ebrey Dir., Staff Ex. 3.0 Corr., 37:841-42:973. The proposal is flawed because the Utilities incur costs to add new customers to their systems and the proposed customer charges, except for North Shore's S.C. No. 1, would recover less than 100% of fixed customer costs. The proposal means that additional distribution revenues received by the Utilities that would recover some of the cost to connect new customers to their systems would be refunded to customers. However, the Utilities would not oppose the proposal if the rider addresses customer switching, as described below. Grace Reb. NS-PGL Ex. 28.0, 21:446-460.

For S.C. No. 1, Peoples Gas proposed to recover 90% of its fixed customer costs through the customer charge and North Shore proposed to recover 100%. If the Commission approves these proposals, the Utilities would not oppose Ms. Ebrey's proposal for S.C. No. 1. For S.C. No. 2, the problem under her proposal is substantial because the Utilities would recover lesser percentages of fixed costs through the customer charge (40% for Peoples Gas and 59% North Shore). Appropriate cost recovery for S.C. No. 2 would additionally be problematic due to the potential for customers to switch service to and from S.C. No. 2. Customer switching is a problem because Rider VBA applies only to S.C. Nos. 1 and 2. If larger S.C. No. 2 customers' usage were to increase such that they would no longer be eligible for S.C. No. 2 and transferred to S.C. No. 4 (S.C. No. 3 for North Shore), total actual S.C. No. 2 revenues would decline due to customer migration, resulting in likely charges to customers when compared to the baseline Rate Case Revenue amount for S.C. No. 2, which included the usage and related distribution charge revenue for the customers who transfer. Conversely, if larger S.C. No. 3 (North Shore) and S. C. No. 4 (Peoples Gas) customers' usage were to decrease such they would become eligible for S.C. No. 2 in a future period when they were not included in the S.C. No. 2 Rate Case Revenue amount, total actual distribution charge revenues would increase due to customer migration, likely resulting in refunds to customers and a loss in the revenue requirement for the Utilities that would be associated with migration rather than an increase in customers. To address this problem, if Ms. Ebrey's proposal is adopted, the Utilities proposed specific wording to exclude revenues from the actual or rate case revenue calculation, as appropriate, to prevent over- or under-collection associated with customer switching. Grace Reb., NS-PGL Ex. 28.0, 21:454 - 23:503; NS-PGL Ex. 45.5. Ms. Ebrey opposed the proposal to address customer migration as an unnecessary complication, although she invited the Utilities to provide additional support in their surrebuttal testimony. Ebrey Reb., Staff Ex. 12.0, 27:494 - 28:501. The Utilities provided additional support by showing, in detail, how the migration and factors causing it affected Rider VBA historically, and absent the Utilities proposal, could adversely affect customers and the Utilities under Ms. Ebrey's proposal. Grace Sur., NS-PGL Ex. 45.0, 21:480 - 25:533.

GCI witness Dr. Dismukes opposed making Rider VBA permanent and offered a variety of policy arguments, many focused on energy efficiency and whether or to what extent decoupling is justified only if the Utilities promote energy efficiency. Dismukes Dir., GCI Ex. 4.0; Dismukes Reb., GCI Ex. 9.0. The fundamental problems with Dr. Dismukes' criticisms are: Rider VBA is a full decoupling mechanism and not conditioned on the Utilities increasing their support of energy efficiency initiatives; his "lost revenue" arguments are a distraction because Rider VBA is not a "lost revenue" mechanism; he and GCI witness Mr. Rubin inaccurately define "fixed costs," when, in fact, 100% of the Utilities' costs are fixed; decoupling is consistent with providing rate certainty to customers, although SFV rates would also achieve that goal; he does not dispute the Utilities' sales forecast showing declining load and acknowledges that Illinois law requires the Utilities to implement energy efficiency measures that will cause load to decline. Grace Reb., NS-PGL Ex. 28.0, 26:576-34:754; Grace Sur., NS-PGL Ex. 45.0, 19:383-23:471.

Rider VBA, as modified, should be approved on a permanent basis. The pilot period showed that it worked as designed and intended.

C. <u>Rider ICR</u>

Peoples Gas proposed no substantive changes to Rider ICR but made minor changes to accommodate their storage unbundling. Grace Dir., PGL Ex. 12.0 Rev., 51:1147-1148.

1. Accumulated Deferred Income Taxes

GCI witness Mr. Effron recommended that Rider ICR be modified to include accumulated deferred income taxes ("ADIT"). Effron Dir., GCI Ex. 2.0, 7:139-143. This is inconsistent with Rider ICR's design. Peoples Gas modeled Rider ICR on Commission rules applicable to water and sewer investments (83 Ill. Admin. Code Part 656). ADIT is not part of those rules. Grace Reb., NS-PGL Ex. 28.0, 41:886-888. If ADIT is included in the rider, actions must be taken to avoid violation of the normalization rules. The normalization rules are complex, and the repercussions of violating them are severe. To highlight one complexity, as a practical matter, the tax normalization rules preclude the consideration of an economic benefit related to accelerated depreciation (including bonus depreciation) in the aggregate set of estimates and projections that are used to set cost of service rates. For example, if the Rider ICR calculation considers a deferred tax liability for accelerated depreciation deductions, but does not consider the fact that the taxpayer net operating loss carry forward position has increased due to those same accelerated depreciation deductions, then the taxpayer would be in violation of the normalization requirements due to imputing an economic benefit that is greater than the utility has realized. Stabile Reb., NS-PGL Ex.26.0, 23:529 - 26:609. Including ADIT in the Rider ICR calculation is not consistent with the design of the rider and it poses significant and unnecessary risks associated with normalization requirements. Staff witness Mr. Kahle agreed that ADIT should not be included. Kahle Reb., Staff Ex. 10.0, 22:479-23:502. Mr. Effron's proposal should be rejected.

IX. COST OF SERVICE

A. Overview

Only the Utilities prepared ECOSSs, which they used to develop rate design proposals. Hoffman Malueg Dir., NS Ex. 13.0, 1:17-20, NS Exs. 13.1 - 13.8; PGL Ex. 13.0, 1:17-20, PGL Exs. 13.1 - 13.8. No party contested the ECOSSs' adequacy and sufficiency. Only limited issues exist concerning three classification matters, and some of these may actually pertain to the Utilities' rate design decisions. *See, e.g.,* Hoffman Malueg Reb., NS-PGL Ex. 29.0, 5:104-106; 13:293 - 14:303.

B. Embedded Cost of Service Study

The ECOSS preparation involves three fundamental steps: (1) cost functionalization; (2) cost classification; and (3) cost allocation. Hoffman Malueg Dir., NS Ex. 13.0, 7:137 - 9:185; PGL Ex. 13.0, 7:137 - 9:185. Utilities witness Ms. Hoffman Malueg explained in detail how she performed each of these three fundamental steps and the methodologies to allocate various categories of costs. Hoffman Malueg Dir., NS Ex. 13.0, 8:151 - 25:564, 25:566-571; PGL Ex. 13.0, 8:151 - 27:600, 27:602-607.

The Utilities' ECOSSs showed their RORs under present and proposed rates. Hoffman Malueg Dir., NS Ex. 13.0, 33:765 - 34:789; PGL Ex. 13.0, 35:801 - 36:825.

1. Uncontested Issues

a. Sufficiency of ECOSS for Rate Design

The Utilities' ECOSSs are comprehensive and theoretically sound. They are a reasonable estimate of revenue requirements by customer class and support the proposed rates. Hoffman Malueg Dir., NS Ex. 13.0, 35:790-794; PGL Ex. 13.0, 36:826-830. Staff reviewed the Utilities'

ECOSSs and concluded that each was an acceptable guidance tool for setting rates. Harden Dir., Staff Ex. 7.0, 8:147-151.

2. <u>Contested Issues</u>

a. Classification of Uncollectible Accounts <u>Expenses Account No. 904</u>

The Utilities classify Account No. 904 costs as customer-related. Hoffman Malueg Dir., NS Ex. 13.0, 8:161-167; PGL Ex. 13.0, 8:161-167; Hoffman Malueg Reb., NS-PGL 29.0, 4:72-73. The Utilities allocated Account 904 costs to the customer classes using the Bad Debt allocation methodology. Hoffman Malueg Dir., NS Ex. 13.0, 18:390-395; PGL Ex. 13.0, 19:424-20:429; Hoffman Malueg Reb., NS-PGL 29.0, 4:70-75. The classification and allocation methods are appropriately based on cost-causation. The Commission approved these methods in the Utilities' 2009 rate cases. Hoffman Malueg Reb., NS-PGL Ex. 29.0, 2:35-38; *Peoples 2009*, p. 209.

GCI witness Mr. Rubin opined on the proper allocation and collection of Account No. 904 costs. Rubin Dir., GCI Ex. 3.0, 12:246 -14:293. Cost allocation and cost recovery are distinct issues, the former falling under the ECOSSs and the latter being a rate design decision. Hoffman Malueg Reb., NS-PGL Ex. 29.0, 8:164-183. In Mr. Rubin's rebuttal testimony he contends that his testimony was limited to rate design, and he made no changes to the ECOSSs. Rubin Reb., GCI Ex. 8.0, 11:210-211. Rate design issues are discussed in Section X, *infra*. If Mr. Rubin is questioning the propriety of the Utilities' treatment of Account 904 costs in their ECOSSs, the Utilities showed that their functionalization, classification and allocation were appropriate and consistent with the 2009 rate cases Order.

b. Classification of A&G Related to O&M

The Utilities use "Total O&M, Not Including A&G" as the classification method for A&G related to O&M expense. Hoffman Malueg Dir., NS Ex. 13.0, 19:412-415; PGL Ex. 13.0, 20:445 - 21:449. This classification method is appropriate based on cost-causation, is recommended by the American Gas Association ("AGA") and National Association of Regulatory Utility Commissioners ("NARUC"), and was uncontested in the Utilities' 2009 rate cases. Hoffman Malueg Reb., NS-PGL Ex. 29.0, 2:39-44. 9:186-12:260.

GCI witness Mr. Rubin appears to suggest that Account 904 costs should be excluded from this method. Rubin Dir., GCI Ex. 3.0, 15:297-303. Again, it is unclear if Mr. Rubin is addressing the ECOSSs or rate design. Rubin Reb., GCI Ex. 8.0, 11:210-211.

A&G related to O&M Expense consists of FERC Primary Accounts 920-923 and 927-931, which are for expenses such as salaries, office supplies expense, and miscellaneous general expense. The Utilities incur these costs to administer their business and uncollectibles expense is part of their day-to-day operations. The Utilities' approach is consistent with the AGA's Gas Rate Fundamentals and NARUC's Gas Distribution Rate Design Manual. While these reference materials specifically exclude gas costs from the classification method, neither recommends excluding Account 904. Hoffman Malueg Reb., NS-PGL Ex. 29.0, 10:298-224. The classification method encompasses all of the potential relations to activities thereby being the most representative of the activities for which expenses are booked to the A&G accounts. Hoffman Malueg Reb. NS-PGL Ex. 29.0, 11:249-12:260.

c. Classification of Fixed Costs

The Utilities correctly defined and classified fixed costs in their ECOSSs based on how they incur costs. Hoffman Malueg Reb., NS-PGL Ex. 29.0, 13:290 - 17:382. The classifications are: commodity, demand, and customer. Commodity classified costs are costs that vary with throughput. Demand classified costs are incurred to serve the system peak demand and do not directly vary with customer count and usage; they vary with the quantity or size of plant and equipment required to serve the system peak demand. Customer classified costs are incurred to extend service and attach a customer to the distribution system, meter gas usage, and maintain the customers' accounts. Typically, customer classified costs are those types of costs that vary with the number and density of customers; they do not vary with customers' consumption. Once costs are classified, customer count changes would not be a reason to change the classification. NS-PGL Ex. 29.4.

GCI witness Mr. Rubin incorrectly concluded that the Utilities "improperly identified essentially all of their costs as being 'fixed' in nature." Rubin Dir., GCI Ex. 3.0, 3:55-56. While customer classified costs are sometimes referred to as "fixed costs," that does not mean they are a utility's only fixed costs. Also, while demand classified costs are classified as such based on how the costs are incurred by the peak demands placed on a Utilities' systems, that does not mean they are not considered fixed costs. Finally, simply because demand classified costs are allocated to service classifications using a volumetric-based allocation method, such as the Average & Peak demand allocation, does not mean the costs are not fixed in nature. Hoffman Malueg Reb., NS-PGL Ex. 29.0, 14:307-314.

X. RATE DESIGN

A. Overview

The Utilities' proposed rate designs were intended to and would accomplish the following eight major objectives: (1) recover the Utilities' revenue requirements; (2) better align revenues with underlying costs; (3) send the proper price signals; (4) provide more equity between and within rate classes; (5) maintain rate design continuity; (6) reflect gradualism; (7) retain customers on the Utilities' systems; and (8) effectively and fairly unbundle costs and charges for standby and storage services. Grace Dir., NS Ex. 12.0 REV, 7:143-148; PGL Ex. 12.0 REV, 7:142-147.

B. General Rate Design

1. Allocation of Rate Increase

The Utilities' ECOSSs and the descriptions of the Utilities' rate design, including the supporting exhibits, are detailed and specific enough that it would be straightforward to derive rates from whatever revenue requirement the Commission approves. No other party prepared cost of service studies or a comprehensive rate design to implement a Commission order.

2. Uniform Numbering of Service Classifications

Staff witness Ms. Harden recommended that the Utilities analyze implementing uniform service classification numbering in future rate cases. Harden Dir., Staff Ex. 7.0, 4:78-79. The Utilities agreed to undertake this review. Grace Reb., NS-PGL Ex. 28.0, 6:118-121.

C. Service Classification Rate Design

1. Uncontested Issues

a. North Shore Service Classification No. 2

North Shore proposed to increase the S.C. No. 2 monthly customer charge and move the charges for all three meter classes closer to cost. Fixed costs include customer and demand costs. The proposed customer charges for meter classes 1, 2 and 3 recover 95%, 20% and 10% of their respective non-storage related demand costs. If the Commission approves proposed Rider UEA-GC, the customer charge would be the same for sales and transportation customers; if not, the sales customer charge would be higher. North Shore proposed to maintain the three declining block distribution charge for S.C. No. 2 and allocate the remaining costs to the blocks. Only 58.6% of the S.C. No. 2 revenue requirement would be recovered through fixed customer charges. North Shore proposed to recover all storage related demand costs through proposed Rider SSC, Storage Service Charge. About 38.9% of fixed costs would continue to be recovered through volumetric distribution charges. Grace Dir., NS Ex. 12.0 Rev., 18:388-20:443; NS Ex. 12.1, pp. 6-7; NS Ex. 12.7. Staff witness Ms. Harden recommended approval of North Shore's proposal. Harden Dir., Staff Ex. 7.0, 13:267 - 16:330.

b. <u>North Shore Service Classification No. 3</u>

North Shore proposed setting the S.C. No. 3 customer charge at cost. The demand charge would recover 67% of non-storage related demand costs. The monthly standby service charge would be eliminated, with storage costs being recovered under Rider SSC. The distribution charge would recover remaining non-storage related demand costs. Grace Dir., NS Ex. 12.0 REV, 20:444-455; NS. Ex. 12.1, p. 8. Staff witness Ms. Harden recommended approval of North Shore's proposal. Harden Dir., Staff Ex. 7.0, 16:335-18:372.

c. <u>Peoples Gas Use of Equal Percentage of Embedded Cost Method ("EPECM")</u>

Peoples Gas used the ECOSS to set S.C. Nos. 4 and 8 at cost and proposed to apportion the remaining revenues to be recovered from S.C. Nos. 1 and 2 using the equal percentage of embedded cost method ("EPECM"), which allocates the increase in proportion to their embedded cost of service. The Commission approved the EPECM in Peoples Gas' last four rate cases (Docket Nos. 91-0586, 95-0032, the 2007 rate case, and the 2009 rate case). The EPECM provides a gradual movement toward equalizing rates of return by allocating the increase portion of the total revenue requirement on a cost of service basis. Grace Dir., PGL Ex. 12.0 REV, 8:172-9:187; PGL Ex. 12.3.

Under Peoples Gas' proposal, S.C. No. 1 would be at 98.6% of cost. This compares with 89.9% (Docket 95-0032), 92.3% (2007 rate case) and 94.7% (2009 rate case) of cost under final rates. The proposed allocation provides reasonable movement toward cost and mitigates bill impacts. Peoples Gas is not applying the EPECM to all embedded costs. Under the storage unbundling proposal, it would recover storage costs from all applicable service classifications at cost. Grace Dir., PGL Ex. 12.0 REV, 9:194-11:226. Staff witness Ms. Harden recommended approval of the EPECM (Harden Dir., Staff Ex. 7.0, 7:139-8:145).

d. **Peoples Gas Service Classification No. 2**

Peoples Gas proposed to increase the S.C. No. 2 monthly customer charges and move the charges for all three meter classes closer to cost. Fixed costs include customer and demand costs. The proposed customer charges for meter classes 1 and 2 recover 50% and 15% of their respective non-storage related demand costs, but, in the interest of gradualism, no demand costs are recovered through the proposed meter class 3 customer charge. If the Commission approves proposed Rider UEA-GC, the customer charge would be the same for sales and transportation customers; if not, the sales customer charge would be higher. Peoples Gas proposed to maintain the three declining block distribution charge for S.C. No. 2 and allocate the remaining costs to the blocks. Only 40% of the S.C. No. 2 revenue requirement would be recovered through fixed customer charges. Peoples Gas proposed to recover all storage related demand costs through proposed Rider SSC. About 49% of fixed costs would continue to be recovered through volumetric distribution charges. Grace Dir., PGL Ex. 12.0 REV, 20:435 - 21:473; PGL Ex. 12.1, pp. 6-7; PGL Ex. 12.7. Staff witness Ms. Harden recommended approval of Peoples Gas' proposal. Harden Dir., Staff Ex. 7.0, 13:267-16:330.

e. Peoples Gas Service Classification No. 4

Peoples Gas proposed setting the S.C. No. 4 customer charge at cost. The demand charge would recover 56% of non-storage related demand costs. The monthly standby service charge would be eliminated, with storage costs being recovered through a new charge under Rider SSC. The distribution charge would recover remaining non-storage related demand costs. Grace Dir., PGL Ex. 12.0 REV, 22:495-23:505; PGL Ex. 12.1, p. 8. Staff witness Ms. Harden recommended approval of Peoples Gas' proposal. Harden Dir., Staff Ex. 7.0, 16:335-18:372.

f. Peoples Gas Service Classification No. 8

Peoples Gas proposed to set S.C. No. 8 at cost. Grace Dir., PGL Ex. 12.0 REV, 23:508-510; PGL Ex. 12.1, p. 9. Staff witness Ms. Harden recommended approval of Peoples Gas' proposal. Harden Dir., Staff Ex. 7.0, 19:391-393.

2. Contested Issues – North Shore and Peoples Gas

a. Service Classification No. 1

The Utilities each proposed that its S.C. No. 1 monthly customer charges would increase for sales and transportation customers. If the Commission approves proposed Rider UEA-GC, discussed in Section VIII.A, *supra*, the monthly customer charge for sales and transportation customers would be the same; if not, the sales customer charge would be higher. The distribution charge would reflect decreases in both blocks of the two-block rate structure. Grace Dir., NS Ex. 12.0 REV, 11:231-233, 12:268-13:291, NS Ex. 12.1, p. 5; PGL Ex. 12.0 REV, 12:267-269, 14:308 - 15:337, PGL Ex. 12.1, p. 5.

Peoples Gas is proposing to recover 90% of its customer related costs, excluding gas cost related Account 904 costs and transportation administrative costs, through the customer charge.

For North Shore, it is 100%. Grace Dir., NS Ex. 12.0 REV, 12:266-268; PGL Ex. 12.0 REV, 14:306-308.

In the interest of gradualism, Peoples Gas is proposing to set the S.C. No. 1 customer charges below its embedded and allocated fixed costs. (Embedded costs are those arising out of the ECOSS while allocated costs are those arising from the application of the EPECM to embedded costs.) North Shore is proposing to set the charges at embedded costs. (North Shore is proposing to set all its service classifications at cost, and, therefore, only embedded costs are relevant.) Grace Dir., NS Ex. 12.0 REV, 13:291-292; PGL Ex. 12.0 REV, 15:337-16:339.

In the interest of rate design continuity, the Utilities each proposed to recover all non-storage related demand costs through volumetric distribution rates rather than a fixed charge. For Peoples Gas, only 62% of fixed costs would be recovered through the customer charges and, for North Shore, only 69%. The Utilities each proposed to recover all storage related demand costs through proposed Rider SSC. For Peoples Gas, about 31% of fixed costs would continue to be recovered through volumetric distribution charges and for North Shore the amount is 29%. Grace Dir., NS Ex. 12.0 REV, 13:292-14:301; PGL Ex. 12.0 REV, 16:339-347.

The Utilities proposed to maintain a two declining block rate structure for S.C. No. 1. The front block (0 - 50 therms) charge is based on allocating about 65% of remaining customer, non-storage related demand and commodity costs, consistent with the percentage allocated in the 2009 rate case. For North Shore, it is 67%. The remainder of the revenue requirement would be collected through an end block (over 50 therms) distribution charge. Grace Dir., NS Ex. 12.0 REV, 14:303-309, NS Ex. 12.1, p. 5; Grace Dir., PGL Ex. 12.0 REV, 16:349-355, PGL Ex. 12.1, p. 5.

Increasing the percentage of fixed costs recovered through fixed charges is appropriate as a matter of cost causation and Commission policy. 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 rate cases, the Commission found it appropriate that rates reflect a greater recovery of fixed costs in customer charges. In a Union Electric rate case (ICC Docket No. 03-0009), the Commission endorsed efforts to recover all of a utility's fixed customer related costs of serving residential customers through the customer charge component of rates as well as a gradualism approach to doing so. As stated in Section VIII.B, *supra*, 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. Last, in the Utilities' 2009 rate cases, the Commission stated that: "The Utilities are correct that the Commission has been increasing the proportion of fixed costs recovered through the customer charge in other proceedings. [citations omitted]. The Commission notes that the Utilities' proposal does not approach the level of fixed costs approved in those dockets. … Moreover, in the event that Rider VBA is not renewed, the slight increase proposed by the Utilities' here would be a benefit in the long run." (*Peoples 2009*, p. 218). Grace Dir., NS Ex. 12.0 REV, 15:329-16:348; PGL Ex. 12.0 REV, 17:375-18:394.

Peoples Gas proposed that Rider VBA be approved on a permanent basis, but GCI witnesses opposed this proposal. If the Commission does not permanently approve Rider VBA, the S.C. No. 1 customer charges would be well below their embedded fixed cost. Grace Dir., NS Ex. 12.0 REV, 15:323-327; PGL Ex. 12.0 REV, 17:369-375. With Rider VBA in place, increasing fixed cost recovery through fixed charges is sound rate design policy, but, if the

Commission declines to make Rider VBA permanent, it is appropriate that SFV rates be adopted, *i.e*., recovery of 100% of fixed costs in the customer charge.

SFV is the most appropriate rate design to best align revenue recovery with its mostly fixed costs. However, while SFV rates would offer stability to the Utilities and their customers and eliminate the need for a decoupling rider, some may view SFV rates as too significant a departure from the Utilities' current rate structure. An SFV rate would be equivalent to putting customers on a budget plan for the delivery service portion of their bill but without any need for a true-up. Customers would pay a fixed monthly charge and the delivery portion of their bill would be unaffected by variations in weather or other conditions. As a result, they would not over or under pay for the services that they receive. An SFV rate would also lower the delivery charge portion of a customer's bills during the winter period when gas usage and market commodity prices are typically at their highest. An SFV rate would be especially beneficial to high usage customers who live in energy inefficient housing, particularly those who are low income, as with SFV, the delivery charge portion of the bill would be almost entirely fixed. The largest portion of a small residential customer's bill, the cost of gas, would continue to send the proper signal that higher usage would result in a higher bill due to a greater consumption of gas, the price of which is largely affected by market forces. Grace Dir., NS Ex. 12.0 REV, 16:351 - 17:376; PGL Ex. 12.0 REV, 18:397-19:422.

GCI witness Mr. Rubin's principal issues concerning S.C. No. 1 rate design focus on defining fixed costs and determining how to recover those costs. Rubin Dir., GCI Ex. 3.0, 4:90 - 11:231. As discussed in Section IX.B.2.c, *supra*, the Utilities have properly classified costs as fixed. The Utilities recognize that there are disagreements on how to allocate and recover fixed costs. Absent a fixed demand charge, it is appropriate that such fixed costs be recovered through a fixed charge such as the customer charge, or spread between the customer and commodity charges. However, the Utilities have chosen to recover S.C. No. 1 demand costs through the distribution charges in a manner that the Commission previously approved. Grace Reb., NS-PGL Ex. 28.0, 8:153-9:177.

The Utilities' proposed S.C. No. 1 rate design, including making Rider VBA permanent, should be approved. Staff witness Ms. Harden recommended approval of the Utilities' proposal (Harden Dir., Staff Ex. 7.0, 8:166-13:263). If the Commission does not make Rider VBA permanent, then SFV rates are appropriate. The GCI proposals both to reduce fixed cost recovery through fixed charges and not make Rider VBA permanent are particularly inappropriate and should be rejected.

D. Tariffs – Other Non-Transportation Tariff Issues

1. Uncontested Issues - North Shore and Peoples Gas

a. Terms and Conditions of Service

The Utilities proposed to move, but not change, the definition of Critical Days from Rider SST to the Terms and Conditions of Service. The Utilities also proposed a new definition, Operational Flow Order ("OFO") Day, that would be included in the Terms and Conditions of Service. Grace Dir., NS Ex. 12.0 REV, 27:610-28:622; PGL Ex. 12.0 REV, 30:665-677.

b. Service Activation Charges

The Utilities each proposed to increase their Service Activation Charges, which recover a portion of the costs for initiating gas service. The charges apply to customers moving into or within the service territory. The Utilities perform two types of service activations, a succession turn-on for which only a meter reading is taken, and a straight turn-on for which gas has to be turned on and appliances have to be relit. The Utilities' proposed charges would collect a greater percentage of, but not all, costs from customers causing their incurrence. For Peoples Gas, the proposed charges are: $18 for a succession turn-on, $30 for a straight turn-on, and $10 charge for relighting each appliance over four. For North Shore, the proposed charges are: $20 for a succession turn-on, $42 for a straight turn-on, and $10 charge for relighting each appliance over four. Grace Dir., NS Ex. 12.0 REV, 21:474-22:490; NS Ex. 12.9; PGL Ex. 12.0 REV, 24:529 - 25:545; PGL Ex. 12.9. Staff witness Ms. Harden recommended approval of the proposed charges. Harden Dir., Staff Ex. 7.0, 37:784-786.

c. <u>Service Reconnection Charges</u>

The Utilities assess a Service Reconnection Charge to a customer whose gas has been turned off. Each customer is granted a waiver of one reconnection charge each year, except when the customer voluntarily disconnects and then requests reconnection within twelve months or when service is disconnected at the main. The Utilities analyzed the costs for: basic reconnections that only require a meter turn-on, reconnections that require setting a new meter, and reconnections that involve excavating at the main. The Utilities each proposed to increase each charge to collect a higher percentage of, but not all, the costs from the customers creating the costs. North Shore and Peoples Gas each proposed: $75 for a basic reconnection; $150 when the meter has to be reset; and $425 when service has to be reconnected at the main. The charge for relighting each appliance over four would be increased from $5 to $10, as with the Service Activation Charge. Grace Dir., NS Ex. 12.0 REV, 22:493-23:514, NS Ex. 12.9; PGL Ex. 12.0 REV, 25:548-26:569, PGL Ex. 12.9. Staff witness Ms. Harden recommended approval of the proposed charges. Harden Dir., Staff Ex. 7.0, 37:784-786.

d. Rider 2

The Utilities proposed revising Rider 2 to add a new Storage Gas Charge, to recover gas cost related storage costs, applicable to certain transportation riders. For Riders FST and FST-T, which remain bundled services, customers would continue to pay for gas charge related storage and standby service through the Standby Demand Charge, but without the application of a Diversity Factor. Grace Dir., NS Ex. 12.0 REV, 46:1045-48:1075; PGL Ex. 12.0 REV, 49:1104 - 51:1134. The Utilities proposed to simplify certain language addressing gas that they buy and sell under the transportation riders. Grace Dir., NS Ex. 12.0 REV, 48:1077-1080; PGL Ex. 12.0 REV, 51:1136-1139.

e. Rider 9

The Utilities proposed to add language to Rider 9 to define the charges for unauthorized use of gas service in conjunction with the transportation proposals. Grace Dir., NS Ex. 12.0 REV, 48:1083-1085; PGL Ex. 12.0 REV, 51:1142-1144.

E. Bill Impacts

The Utilities prepared detailed bill impact analyses for all service classifications affected by their rate proposals, at various usage levels under present and proposed rates. The Utilities' proposed rate designs and resulting bill impacts are consistent with the objectives of continuity and gradualism. Grace Dir., NS Ex. 12.0 REV, 21:462-466; NS Ex. 12.8; PGL Ex. 12.0 REV, 23:517-521; PGL Ex. 12.8.

XI. TRANSPORTATION ISSUES

A. Overview

The Utilities offer small volume and large volume transportation programs. Their programs are substantially identical. The large volume program is Rider FST, Full Standby

Transportation Service, and Rider SST, Selected Standby Transportation Service. Alternative gas suppliers may pool customers under Rider P, Pooling Service. The large volume transportation ("LVT") program is available to North Shore's S.C. Nos. 2 and 3 customers and Peoples Gas' S.C. Nos. 2, 4 and 8 customers. The small volume program is known as Choices For You[sm] and offered under Rider CFY. Alternative gas suppliers aggregate Rider CFY customers under Rider AGG, Aggregation Service. The small volume transportation ("SVT") program is available to North Shore's S.C. Nos. 1 and 2 customers and Peoples Gas' S.C. Nos. 1, 2, and 8 customers. McKendry Dir., NS Ex. 15.0, 3:48-56; PGL Ex. 15.0, 3:51-56.

For the LVT program, the Commission, in the 2009 rate cases Order, concluded that:

> The Commission agrees that it is reasonable for the Utilities to work with Staff and all other interested stakeholders to develop reasonable proposals for unbundling storage service. The Commission finds that the Utilities should file any agreed upon proposals in their next rate cases. To the extent Staff, participating stakeholders and the Utilities do not reach agreement, the Utilities should address this matter in those rate cases.

Peoples 2009, p. 235. The Commission, for the SVT program, directed the Utilities to participate in workshops to address specified aspects, notably including "Allocation of and Access to Company-owned Assets," of that program. *Id*. at 253.

In response to the 2009 rate cases Order, the Utilities conducted two primary analyses modeling the capabilities of their assets -- one modeling the daily injection and withdrawal rights and another modeling the month-end storage inventory target levels. Connery Dir., NS Ex. 14.0, 6:110-112; PGL Ex. 14.0, 6:110-112. Based on those analyses and adjustments made during the workshop process, the Utilities filed changes to the SVT program that took effect in March 2011. Connery Dir., NS Ex. 14.0, 5:99-102, 13:261-274; PGL Ex. 14.0, 5:99-102, 12:252-13:264. These analyses provided the framework for addressing the Commission's directive that the Utilities develop proposals to unbundle the LVT program storage service. The unbundling proposal consists of: the replacement of Rider SST with a stand-alone storage service, called Rider SBS, Storage Banking Service; the elimination of standby service from Rider SBS; the inclusion of monthly and daily operating parameters governing the use of Rider SBS storage; and to the extent applicable, the inclusion of storage operating parameters in Rider FST, which remains a bundled service. Connery Dir., NS Ex. 14.0, 2:40-3:63; PGL Ex. 14.0, 2:40-3:63.

B. Uncontested Issues

1. Allowable Bank (AB) Calculation

Each of the Utilities would determine available bank days by dividing its total storage capacity by its design peak day. They would not distinguish "base rate" days and "gas charge" days of bank. Grace Dir., NS Ex. 12.0 REV, 41:921-926; NS Ex. 12.13; PGL Ex. 12.0 REV, 44:980-985; PGL Ex. 12.13.

2. Rider CFY

Rider CFY customers currently pay for base rate storage costs through bundled storage costs in their service classifications. Under the unbundling proposal, Rider CFY customers would pay for base rate storage costs through the Storage Banking Charge under proposed Rider SSC. They would pay for gas charge related storage through the Storage Gas Charge under Rider 2. The hub credit gas charge, which is a credit against the ABGC, will be billed as a separate line item. Grace Dir., NS Ex. 12.0 REV, 40:897-902; PGL Ex. 12.0 REV, 42:940 - 43:954.

3. Rider AGG (except Aggregation Charge)

Currently, the Utilities file a report for the number of days of bank for Rider AGG suppliers. The Utilities proposed to eliminate this report and, in coordination with a comparable

LVT report, have the bank filing occur on April 1, to be effective May 1. Grace Dir., NS Ex. 12.0 REV, 40:904-41:917; PGL Ex. 12.0 REV, 43:963-976.

4. Rider SBO

Rider SBO, Supplier Bill Option Service, allows SVT suppliers to issue their own bills to customers for their services and the Utilities' delivery service. The suppliers receive a credit. The Utilities proposed to increase the credit from $0.35 to $0.46 per bill per month. Grace Dir., NS Ex. 12.0 REV, 25:549-556; NS Ex. 12.11; PGL Ex. 12.0 REV, 27:604-611; PGL Ex. 12.11.

C. Administrative Charges

The Utilities have a Gas Transportation Services ("GTS") department. The department manages gas transportation-related contracts, nominations, billing and support work related to customers, their accounts and gas metering equipment. It also provides certain services, billing, and support to SVT and LVT alternative gas suppliers. McKendry Dir., NS Ex. 15.0, 4:64-67; PGL Ex. 15.0, 4:64-67. The Utilities apply administrative charges to the contract and pool level accounts to recover GTS costs. For example, a Rider FST customer has a contract with the utility, and it may include more than one account. That customer pays an Administrative Charge for each account. NS Ex. 12.1, p. 48; PGL Ex. 12.1, p. 49. Proposed Rider SBS would have an Administrative Charge assessed per account. NS Ex. 12.1, p. 96; PGL Ex. 12.1, p. 97. An alternative gas supplier may have a pool comprised of as many as 300 customer accounts under Rider P and an unlimited amount under Rider AGG. That supplier pays a Pooling Charge (Rider P) or an Aggregation Charge (Rider AGG), consisting of a monthly charge plus a charge for each account in the pool. NS Ex. 12.1, pp. 71, 82; PGL Ex. 12.1, pp. 70, 82. McKendry Dir., NS Ex. 15.0, 4:78-84; PGL Ex. 15.0, 4:78-84. Rider CFY customers must be in pools, and all

GTS administrative costs associated with the SVT program are assessed to suppliers and not customers. NS Ex. 12.1, pp. 77-78, 82; PGL Ex. 12.1, pp. 76-78.

As in prior rate cases, the per account charges are based on a cost study. McKendry Dir., NS Ex. 15.0, 2:24-27; PGL Ex. 15.0, 2:24-27. That study identifies the three significant categories of costs (GTS labor, GTS other (*i.e.*, non-labor), and IT). The costs are allocated to Rider FST (not pooled), Rider SST/SBS (not pooled), Rider P, and Rider CFY. The study includes credits for LVT program imbalance trade charges, SVT billing service, and the "per pool" administrative charge.[71] Importantly, the study includes only costs that directly support the transportation programs. Thus, for any planned activity by GTS that is not transportation-related work, the study removes those costs. Examples include work for customer accounts that are not currently active on one of the transportation programs. Most often this would occur when a transportation customer has additional accounts that are not on a transportation program or when GTS performs complex billing transactions, such as special metering and instruments or special billing, for non-transportation customers. McKendry Dir., NS Ex. 15.0, 5:85-101; NS Ex. 15.1; PGL Ex. 15.0, 5:85-101; PGL Ex. 15.1. Also addressing the fact that some GTS work does not support transportation services, the cost study assumes 15 GTS employees (McKendry Tr. 9/1/11, p. 673) even though the department has 17 employees (NS Ex. 15.0, 3:62; PGL Ex. 15.0, 3:62). The proposed administration charges, except for Peoples Gas' Rider P per account charge, are lower than the current charges. In fact, the test year forecast is significantly (8%) lower than the actual 2010 costs. McKendry Reb., NS-PGL Ex. 31.0, 3:62-64; NS-PGL Ex. 31.1.

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[71] As stated above, the supplier pays an administrative charge that is a fixed amount per month per pool plus a per account charge. The purpose of the cost study is to develop the per account charges, so the fixed pool charge is backed out through a credit.

Staff witness Mr. Sackett questioned the study and proposed downward adjustments based on what he considered over-budgeting. Sackett Dir., Staff Ex. 9.0, 7:131-8:156. Mr. Sackett's proposed adjustments should be rejected. The budget used to develop the test year costs is based upon the best available information at the time regarding future enrollment and GTS and IT costs required in support of the programs. If historical budgets exceeded actual costs in the three years that Mr. Sackett reviewed, this does not mean the budget process is flawed. Many variables, especially unanticipated events, affect actual costs. For example, in two of the three years that Mr. Sackett reviewed (2008 and 2009), the Utilities were in the midst of merger-related activity. While the budget included two additional positions for GTS, a hiring freeze occurred and those two positions were never filled. In 2008, three employees retired and one more moved into another position within the company. Later, GTS replaced a few of those experienced employees with newer employees. McKendry Reb., NS-PGL Ex. 31.0, 3:47-60.

Mr. Sackett's approach of reducing the test year budget by calculating a factor by which cost categories in prior years' budgets exceeded actual costs (Sackett Dir., Staff Ex. 9.0, 7:141 - 8:147; Sackett Reb., Staff Ex. 18.0, 4:70-5:90) assumes that unexpected events that caused costs to be lower than forecast would occur again. For example, if an unplanned and unexpected merger-related reduction in projected and actual employee count caused past actual results to differ from the past budgets, applying a factor to reduce the 2012 budget because of that past event's impact, in effect, assumes a reduction in employee count that is not projected to occur. McKendry Sur., NS-PGL Ex. 47.0, 3:51-55. Mr. Sackett has not identified specific flaws with the current budget (*e.g.*, he presented no evidence that the GTS employee complement is over-stated or that events such as a merger were expected to affect the GTS budget). Instead, his recommended reduction is based on applying a factor derived from recent years' data, which, given the specific sorts of events identified by the Utilities as affecting those years' data (notably the merger), is not a reasonable approach.

Interstate Gas Supply, Inc. ("IGS") witness Mr. Parisi argues that the SVT administrative charges be assessed to all customers eligible for the program. This recommendation is addressed and refuted in Section XI.E.1, *infra*.

D. Large Volume Transportation Program

1. Administrative Charges

Staff witness Mr. Sackett recommended a reduction in the forecast costs underlying the administrative charges applicable to the LVT and SVT programs. This recommendation is addressed and refuted in Section XI.C, *supra*.

2. Transportation Storage – Issues

As stated above, the Commission directed "the Utilities to work with Staff and all other interested stakeholders to develop reasonable proposals for unbundling storage service." The Utilities proposed Rider SBS to meet this directive and allow LVT customers to select the amount of storage service they wish to receive. The analysis that supported this rider prompted changes to Rider FST and corresponding changes to Rider P. Proposed Rider SSC is the cost recovery mechanism that ensures that customers pay only for the storage that they receive. As discussed below, the Utilities proposed to implement LVT changes on August 1, 2012, thus allowing the Utilities, customers and suppliers a transition period; accordingly, the Utilities have also proposed transition riders for existing services. The Utilities' proposals fairly allocate available storage-related assets to all customers who use those assets, namely sales customers, SVT customers and their suppliers, and LVT customers and their suppliers. The proposals accomplish the unbundling sought by the Commission and align the LVT programs with the

Commission-required changes to the SVT programs. The principal criticisms of the proposals are that the Utilities have not demonstrated a need (*e.g.*, compromised system integrity or economic harm to sales customers) to change the LVT programs beyond simply making storage available without a link to standby service. Sackett Dir., Staff Ex. 9.0, 11:224-29:651; Kawczynski Dir., CNEG Ex. 1.0, 12:252-26:566; Gorman Dir., IIEC/CNEG Ex. 1.0, 9:166 - 17:337. The fundamental flaw with those criticisms is that Staff and intervenors would perpetuate inter-class subsidies resulting from all classes of customers (sales, SVT and LVT) relying on the same storage assets but receiving different access rights.

By unbundling storage service, the Commission meant proposals to allow Rider SST customers to receive storage service not tied to standby service. *Peoples 2009*, p. 235. Currently, all or part of the storage capacity (called "Allowable Bank" or "AB") that a Rider SST customer receives may be based on its election of standby service. Rider SST customers served under the Utilities' S.C. No. 2 and Peoples Gas' S.C. No. 8 (where storage costs are currently bundled in rates for both rate classes) receive the full amount of base rate storage bank even if they choose zero back-up. If an S.C. No. 2 customer or Peoples Gas S.C. No. 8 customer takes Rider SST service, that customer's selection of standby service will provide for additional storage capacity in the form of gas charge days. The storage capacity that an S.C. No. 3 (North Shore) or 4 (Peoples Gas) customer receives is wholly determined by the amount of standby service the customer selects. Grace Reb., NS-PGL Ex. 28.0, 16:343-348; *also see* NS 12.1, p. 55; PGL Ex. 12.1, p. 56. Standby service allows an LVT customer to buy gas from the Utilities up to an amount that the customer selects. If the customer's gas deliveries, including available storage, are insufficient to meet its requirements, it would buy the difference from the Utilities up to its standby rights. The customer does not nominate standby gas; the purchase happens automatically as an after-the-fact part of the order of deliveries to the customer. In other words, it is a "no-notice" service. Connery Dir. NS Ex. 14.0, 21:446-454; PGL Ex. 14.0, 21:444-452.

In response to the Commission's requirement that they change the allocation of and access to storage rights for the SVT program, the Utilities analyzed their gas supply-related assets that support storage services. The analyses underlying the SVT changes provided much of the framework for the proposed LVT changes. Many of the SVT storage-related terms and conditions translate directly to the large volume program. Connery Dir., NS Ex. 14.0, 7:127-134; PGL Ex. 14.0, 7:129-136. This is because the storage asset pool for the LVT program is, like that for the SVT program, the aggregation of all the Utilities' storage-related assets. The model developing access to and the equitable allocation of storage applies to all customer classes, including the LVT customers. Connery Dir., NS Ex. 14.0, 22:462-470; PGL Ex. 14.0, 21:460-22:468. Staff and intervenors incongruously argue that LVT customers should have different storage rights because they want to use storage differently than other customers. Sackett Dir., Staff Ex. 9.0, 17:378-18:386; Gorman Reb., IIEC/CNEG Ex. 2.0, 7:128-129. The same assets with the same contractual and operating capabilities support service to all the Utilities' customers. Allowing one class of customers superior rights to those assets necessarily means other customers are subsidizing those rights.

From their analysis, the Utilities developed an unbundling proposal that includes: (1) a stand-alone storage service (Rider SBS); (2) monthly inventory targets (minimum and maximum); (3) daily injection and withdrawal limits, with appropriate distinctions for Critical Days and OFO Days; (4) a daily tolerance around the daily ranges as part of the transition to the new service; and (5) elimination of the no-notice standby service. Connery Dir., NS Ex. 14.0, 18:385-19:396; PGL Ex. 14.0, 18:382-393.

Rider SBS, like Rider SST, would be a daily measurement service. Customers would continue to be able to transfer their contracts to a supplier to manage in a pool, and the pool supplier would be able to aggregate many contracts' ABs to take advantage of possible diversity within the pool to stay within monthly and daily requirements. Existing nomination flexibility and AB trading rights remain intact. Connery Dir., NS Ex. 14.0, 19:398-403; PGL Ex. 14.0, 18:395-19:400.

While the Utilities derived the Rider SBS terms and conditions from their analysis of underlying assets, those terms and conditions are substantially more generous than the tariff and operational limitations of those assets. NS Ex. 14.4; PGL Ex. 14.4. For example, the proposals allow for 100% cycling of storage; at the other extreme, the proposal imposes no cycling requirement for North Shore and only 32% cycling for Peoples Gas. In other words, there are months when a transportation customer may have a storage balance at 0% of capacity and other months when the balance may be 100% of capacity; at no time can the Utilities have aggregate storage balances at those extremes, *i.e.*, the proposed rights exceed the capabilities of the underlying assets. Connery Reb., NS-PGL Ex. 30.0, 12:245-254, 15:323-332. This fully meets Illinois Industrial Energy Consumers/Constellation NewEnergy - Gas Division, LLC ("IIEC/CNEG") witness Mr. Gorman's stated benefit of storage providing a physical hedge. Gorman Dir., IIEC/CNEG Ex. 1.0, 12:233-235. As another example, on a peak day, a transportation customer can meet a substantial portion (75% of its MDQ for Peoples Gas and 64% of its MDQ for North Shore) of its requirements from storage. Connery Reb., NS-PGL Ex. 30.0, 11:222-242. This flexibility contrasts sharply with Mr. Gorman's comment that storage has "virtually no value" under the Utilities' proposal. Gorman Dir., IIEC/CNEG Ex. 1.0, 17:341-343.

The Utilities' thorough analysis for their SVT program and how they applied it to the LVT program is addressed at length in Utilities' witness Mr. Connery's direct testimony and exhibits. The analysis included all storage assets and considered them in the aggregate. This is appropriate even though each storage asset has unique operating capabilities and requirements, generally including daily injection and withdrawal capabilities, peaking capability, and operating guidelines and tariff parameters that must be followed. The Utilities use the storage assets in aggregate to meet daily balancing needs and varying seasonal peak sendout expectations. The storage assets' ability to complement each other in meeting system demands is influenced by dispatch order. For example, Peoples Gas' Manlove Field delivers significant early winter peaking capability and the pipeline storage assets provide coverage of the late winter peaking needs as the Manlove Field peaking capability diminishes. On a daily basis, the Utilities reserve some no-notice pipeline storage balancing capabilities to accommodate changes to sendout and transportation program deliveries subsequent to pipeline nomination deadlines. The daily swing and peaking capabilities of the individual elements of the storage portfolios cannot simply be tallied up to determine an appropriate level of daily injection and withdrawal rights available to the transportation programs. Rather, those rights need to be determined considering how the specific contribution and dispatch timing of the storage assets function in aggregate to meet system demands. Connery Dir., NS Ex. 14.0, 8:169-10:216; PGL Ex. 14.0, 8:170 - 10:210.

The parameters, such as month-end storage inventory target levels and daily injection and withdrawal rates, developed from this analysis, which supported the SVT program changes that are already in effect, apply directly to the LVT program. Connery Dir., NS Ex. 14.0, 22:478-480; PGL Ex. 14.0, 22:476-478. However, in response to a request received during the LVT collaborative process, the Utilities expanded the width of the month-end ranges (*i.e.*, the difference between the high and low balance targets) based on updated model parameters and diversity considerations. Connery Dir., NS Ex. 14.0, 23:491-496; NS Ex. 14.5; PGL Ex. 14.0, 23:489-494; PGL Ex. 14.5. In addition, in response to CNEG witness Mr. Kawczynski's testimony, the Utilities agreed to offer "super pooling" for the monthly target levels, to be implemented twelve months after the Commission issues its final Order in this proceeding. Super pooling is the aggregation of a supplier's contracts for purposes of determining if certain tariff requirements are met. McKendry Reb., NS-PGL Ex. 31.0, 6:127-128. The Utilities proposed that this super pooling would be similar to service in place for the current November end of month storage balance requirement. McKendry Sur., NS-PGL Ex. 47.0, 4:84-6:123.

The daily delivery ranges developed for the SVT program do not have a Rider SST parallel because that concept applies to non-daily read customers. Rider SST customers must have a daily demand measurement device, and Rider SBS customers would likewise have such a device. However, using the daily injection and withdrawal rate schedule from the SVT program represents an equitable allocation of access to storage for Rider SBS. Connery Dir., NS Ex. 14.0, 22:481-23:485, 23:497-502; PGL Ex. 14.0, 22:479-483, 23:495-500. To ease the transition to the new daily rights and obligations, the Utilities proposed a Daily Balancing Tolerance band about the daily injection and withdrawal rights to provide additional storage injection and withdrawal flexibility under Rider SBS. Connery Dir., NS Ex. 14.0, 26:551-27:580; NS Ex. 14.6; PGL Ex. 14.0, 25:549-27:578; PGL Ex. 14.6.

As stated above, Rider SBS would not include a standby service. The assets needed to support this service are fully allocated and available to the unbundled storage service. Connery

Dir., NS Ex. 14.0, 25:529-534; PGL Ex. 14.0, 24:527-25:532. Although disagreeing with other aspects of the proposal, Staff witness Mr. Sackett supports the elimination of standby service from the unbundled tariff. Sackett Dir., Staff Ex. 9.0, 28:631-635.

The Utilities developed a stand-alone storage service based on comprehensive modeling of the assets that support its ability to offer such a storage service. The proposal's key aspect is that all customer classes using these assets – sales, SVT and LVT – would have comparable rights and obligations. Said differently, customers receive the service for which they are paying and no customer class would subsidize another's use of storage. The proposed changes to the LVT program should be approved.

3. Associated Rider Modifications

a. Rider SBS/SST

Rider SBS sets forth the specific storage rights and obligations necessary to implement the unbundling proposal. Rider SST, as described in Section XI.D.3.e, *infra*, would take the form of a transition rider and remain in effect only through July 31, 2012.

Rider SBS would be available to North Shore's S.C. Nos. 2 and 3 customers and Peoples Gas' S.C. Nos. 2, 4 and 8 customers. The new definitions and rates are included as well as a substantially revised Section E, Inventory / Allowable Bank/ Storage Activity, which includes the daily and monthly parameters for storage activity and how these parameters, as well as certain conditions, such as Critical and OFO Days (Supply Shortage and Supply Surplus), affect daily storage activity, and the new AB storage subscription process. Grace Dir., NS Ex. 12.0 REV, 31:697-706, 32:722-34:772; PGL Ex. 12.0 REV, 34:751-760, 33:776-37:829.

Customers would receive AB days with no distinction between base rate and gas charge days. Rider SBS customers would select their storage quantity and other customers (sales, SVT, and Rider FST) would receive the full number of available days. If Rider SBS storage capacity is not fully subscribed, Rider SBS customers may ask to subscribe for additional capacity. (Staff witness Mr. Sackett recommended approval of the proposed subscription process. Sackett Dir., Staff Ex. 9.0, 5:77-78.) Any unsubscribed capacity would be used by sales customers. Grace Dir., NS Ex. 12.0 REV, 32:709-721; PGL Ex. 12.0 REV, 34:763-35:775; McKendry Dir., NS Ex. 15.0, 6:121-8:155; PGL Ex. 15.0, 6:121-8:155.

Riders SST/SBS also include a cost-based charge for the daily demand measurement device, which would continue to be required for these customers. Grace Dir., NS Ex. 12.0 REV, 25:546-549; NS Ex. 12.10; PGL Ex. 12.0 REV, 27:601-604; PGL Ex. 12.10.

b. <u>Rider FST</u>

Rider FST sets forth the specific storage rights and obligations necessary to implement the proposal described in Section XI.D.2, *supra*. Rider FST would continue to be a bundled service, *i.e*., would include standby service and a full complement of AB days. However, on OFO Supply Shortage Days and Critical Supply Shortage Days, customers must deliver some gas, and, if they fail to do so, would receive company gas at a premium price. The limit flows from the same process that shaped the Riders AGG and SBS proposals, namely equitable allocation of storage rights. The delivery requirement represents the non-storage component of the design peak day portfolio. Connery Dir., NS Ex. 14.0, 25:537-545, 31:669-682; NS Ex. 14.1; PGL Ex. 14.0, 25:535-543, 31:667-680; PGL Ex. 14.1.

Month-end storage inventory target balances would be identical to the Rider SBS proposal. The current Maximum Daily Nomination ("MDN") calculation would be revised to apply the same monthly injection rights applicable to Rider AGG and proposed for Rider SBS. (The MDN is the maximum quantity of gas that the customer may nominate during the injection period.) Connery Dir., NS Ex. 14.0, 31:684-32:692; PGL Ex. 14.0, 31:682-32:690. Recognizing that the delivery requirement on some days diminishes the service, the Utilities proposed to reduce the charge for reserving standby service. Standby availability is expected to exceed 95%, but given the introductory nature of the delivery obligation, the Utilities proposed to apply a 20% discount to the firm transportation costs in calculating the Demand Gas Charge. Connery Sur., NS-PGL Ex. 46.0, 10:208-221.

The Utilities proposed specific tariff changes to effectuate the proposal. Grace Dir., NS Ex. 12.0 REV, 36:821-37:834; PGL Ex. 12.0 REV, 39:878-40:891. The proposed Rider FST changes are fully supported by the modeling that underlies the current SVT program and proposed Rider SBS. Just as it is appropriate to remove subsidies from sales customers to transportation customers, it is important that the different LVT riders operate under the same equitable access to storage parameters.

c. Rider P

Rider P applies to suppliers serving LVT customers. The Utilities proposed to revise Rider P to address changes to Rider FST and proposed Rider SBS. Grace Dir., NS Ex. 12.0 REV, 38:858-39:869; PGL Ex. 12.0 REV, 41:916-927.

d. Rider SSC

The Utilities each proposed Rider SSC, Storage Service Charge, to accommodate their storage unbundling proposals. Storage costs are removed from the revenue requirement and recovered separately. Initial charges would be set when proposed rates take effect. The Utilities would determine subsequent charges in an annual filing. Grace Dir., NS Ex. 12.0 REV, 42:952-955, 43:970-977; PGL Ex. 12.0 REV, 45:1012-1015, 46:1030-1037.

Rider SSC sets a Storage Banking Charge for transportation customers and a Storage Service Charge for sales customers. The Storage Banking Charge applies to transportation customers on each therm of storage capacity, and the Storage Service Charge applies to sales customers on each therm of delivered gas. Grace Dir., NS Ex. 12.0 REV, 43:977-44:984; PGL Ex. 12.0 REV, 46:1037-47:1044.

The Storage Banking Charge recovers the production and storage related revenue requirements, excluding the carrying cost of investment in top gas storage. It would initially be determined at currently subscribed transportation storage levels. Actual charges to sales customers would be affected by actual data such as the number of customers taking transportation service and the aggregate amount of their MDQs and selected storage capacity. If transportation customers subscription levels increase, the charge to sales customers would decrease, and *vice versa*. The exclusion of the carrying cost of top gas in storage means that a separately billed storage credit is no longer necessary. Grace Dir., NS Ex. 12.0 REV, 44:987-1017; PGL Ex. 12.0 REV, 47:1047-48:1077.

Staff witness Mr. Sackett recommended approval of Rider SSC. Sackett Dir., Staff Ex. 9.0, 5:83-85. Rider SSC properly addresses the cost recovery aspect of storage unbundling and should be approved.

e. <u>Transition Riders</u>

The Utilities proposed that Rider SBS be effective on August 1, 2012, to allow Rider SST customers time to transition from their current service to Rider SBS. This would also allow the Utilities time to develop and implement the technical programming needed to integrate the new service into their nomination and billing systems, and to effectively educate customers, suppliers and employees about the new service. Grace Dir., NS Ex. 12.0 REV, 34:774-35:781; PGL Ex. 12.0 REV, 37:831-38:838.

Rider SST would remain in effect until Rider SBS becomes effective. Until then, the rider would operate as it does today with a few exceptions and clarifications detailed in Ms. Grace's testimony and the proposed tariffs. Grace Dir., NS Ex. 12.0 REV, 35:785 - 36:812; PGL Ex. 12.0 REV, 38:842-39:869.

The revised Rider FST would take effect August 1, 2012, and, until then, a transition rider, Rider FST-T, would be in effect. Proposed Rider FST-T would be similar to current Rider FST but with a few exceptions similar to the transitional version of Rider SST. Grace Dir., NS Ex. 12.0 REV, 37:841-38:856; PGL Ex. 12.0 REV, 40:898-41:914.

Rider P-T provides interim pooling service for suppliers who deliver gas to Riders SST and FST-T customers, until both terminate on July 31, 2012. Language in Rider P-T has also been revised to align it with the changes proposed for Riders SST and FST-T. Grace Dir., NS Ex. 12.0 REV, 39:871-874; PGL Ex. 12.0 REV, 42:929-932.

The transition riders are necessary to effectuate a smooth transition to the new services. Even if the Commission does not adopt the Utilities' proposal in full, a transition period is appropriate and consistent with how the Utilities have previously implemented changes to their LVT program. *See, e.g., Peoples 2009*, p.231.

E. Small Volume Transportation Program (Choices for You^{SM} or "CFY")

1. Aggregation Charge

Staff witness Mr. Sackett recommended a reduction in the forecast costs underlying the administrative charges applicable to the LVT and SVT programs. This recommendation is addressed and refuted in Section XI.C, *supra*.

The Rider AGG Aggregation Charge is a monthly charge plus a charge for each account in the pool. The charge applies to alternative gas suppliers and not customers. NS Ex. 12.1, p. 82; PGL Ex. 12.1, p. 82. This is consistent with cost causation principles. GTS's current services and the proposed new storage subscription process have been and would be provided to transportation customers and suppliers. Accordingly, it is clear who is causing the costs that have been or would be incurred. For these reasons, the Utilities proposed that the administrative charges for their transportation riders continue to be assessed to transportation customers and suppliers who take service under the riders. Grace Dir., NS Ex. 12.0 REV, 24:529-543; Grace Dir., PGL Ex. 12.0 REV, 26:584-27:598. IGS witness Mr. Parisi argues that the SVT administrative charges be assessed to all customers eligible for the program. Parisi Dir., IGS Ex. 2.0, 31:740-743. Staff witness Mr. Sackett opposed this proposal. Sackett Reb., Staff Ex. 18.0, 7:124-133. Mr. Parisi also argues that the Utilities are improperly recovering certain costs from SVT customers. Parisi Dir., IGS Ex. 2.0, 36:878-37:966. Mr. Parisi's proposal should be rejected, and his contention that the Utilities are improperly recovering certain costs from SVT suppliers is incorrect.

The costs underlying the SVT program are specifically associated with providing services to the suppliers who participate in that program. As sales customers do not cause the costs that are incurred by the GTS department and related IT costs, they should not be assessed any of the costs. Grace Reb., NS-PGL Ex. 28.0, 41:893-898. Mr. Parisi's attempt to compare the Utilities' call center costs, recovered from all customers, with GTS costs recovered from SVT suppliers (Parisi Dir., IGS Ex. 1.0, 34:830-856) is flawed. Sales customers do not call GTS for service and do not pay GTS costs. Suppliers do call GTS (*see* Parisi Dir., IGS Ex. 1.0, 35:846-847), and suppliers pay the costs associated with the services that GTS provides to suppliers. In contrast, both sales customers and transportation customers may call the call center, which serves all customers. Cost causation principles properly result in GTS costs associated with the SVT program being recovered from SVT suppliers and costs such as Call Center costs being recovered from all customers who may use that service. Grace Reb., NS-PGL Ex. 28.0, 41:901-906.

IGS witness Mr. Parisi is incorrect that SVT customers are paying twice for certain costs. Although SVT 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. As examples, functions associated with initiating service to a customer (such as the credit review related to deposit requirements) and terminating service apply to all customers; credit reporting applies to all customers because customers owe the Utilities for delivery service charges and those amounts may become uncollectible expenses; and gas supply personnel provide support for securing and managing the services and assets that underlie storage and balancing services. Grace Reb., NS-PGL Ex. 28.0, 42:910-918.

The Utilities' proposal to continue to recover administrative costs associated with their GTS department and certain transportation-related IT functions from transportation customers and suppliers is supported by cost causation principles and does not result in double recovery of costs from these classes of customers. Indeed, suppliers, who are responsible for the SVT program's Aggregation Charge, pay no administrative costs under the Utilities' service classifications.

2. <u>Purchase of Receivables (withdrawn)</u>

IGS witness Mr. Parisi recommended that the Utilities implement a purchase of receivables program. Parisi Dir., IGS Ex. 1.0, 6:127-30:704. The Utilities opposed the proposal. Schott Reb., NS-PGL Ex. 17.0, 22:483-25:552; McKendry Reb., NS-PGL Ex. 31.0, 4:84 - 6:122. Staff witness Dr. Rearden opposed the proposal. Rearden Reb. Staff Ex. 19.0, 2:39-40, 3:45 - 5:99. Mr. Parisi withdrew his proposal. Parisi Reb., IGS Ex. 2.0, 4:92 - 14:326.

XII. <u>CONCLUSION</u>

Therefore, North Shore Gas Company and The Peoples Gas Light and Coke Company, for all reasons set forth above, appearing of record, or reflected in their draft proposed Administrative Law Judges' Proposed Order to be filed by September 27, 2011, respectfully request that the Commission enter findings and make conclusions on all uncontested and contested issues consistent with the Utilities' positions taken in testimony and/or stated herein regarding the evidence in the record and the applicable law.

John P. Ratnaswamy

Dated: September 22, 2011

By: ______________________________
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